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INTEGRATED ENERGY POLICY REPORT

DISTRIBUTED GENERATION AND DEMAND RESPONSE

WORKSHOP

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John Geesman, Commissioner and Presiding Member

James Boyd, Commissioner and Associate Member

Melissa Jones, Adviser to Commissioner Geesman

Michael Smith, Adviser to Commissioner Boyd

STAFF PRESENT

Scott Tomashefsky

Mark Rawson, PIER Energy Systems Integration

ALSO PRESENT

Judd Putnam, Engineering Services

Richard Seguin, DTE Energy

Tom Bialek, SDG&E, Sempra Energy

Scott Lacy, SCE

John Carruthers, PG&E

Peter Evans, New Power Technologies

Craig McDonald, Navigant

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PUBLIC COMMENT

Jose Luis Contreras, Navigant

Nora Sheriff, Alcantar & Kahl, LLP

Thomas O'Connor, O'Connor Consulting Services

APPEARANCES (continued)

PUBLIC COMMENT (continued)

Gerome Torribio, SCE

Steven Greenberg, US Combined Heat and Power Association

Richard Brent, Solar Turbines

Jim Eyer, Distributed Utility Association

Frances Cleveland, UCI

Jane Turnbull, League of Women Voters

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P R O C E E D I N G S

COMMISSIONER GEESMAN: I want to welcome you to the second day of workshops by the Energy Commission's Integrated Energy Policy Report Committee.

Today's topic is distribution system planning. My name is John Geesman, I'm the Presiding Member of the Commission's Integrated Energy Policy Report Committee.

To my right is Commissioner Boyd, the Associate Member, and the Presiding Member of the 2003 IEPR Committee. To his right is Mike Smith, his Staff Adviser, and joining me shortly will be Melissa Jones, my Staff Adviser.

This topic I think was originally teed up for 2005 IEPR by some comments and recommendations in our 2003 IEPR, which recommended that work be done to bring more transparency to the topic of distribution system planning.

And that's the nature of our interest here today, transparency, trying to gain a better understanding of the considerations that should be observed, as improvements and expansion of the distribution system take place.

Just putting my own take on it, I would contrast today's subject matter from yesterday's. Yesterday's, I think, was more a macro perspective, and I do believe that the state is on a search for megawatts and likely to be fairly forceful in that quest.l

Today I would say it's a bit more of a micro perspective, and to pick up on Commissioner Boyd's phrase yesterday, I believe it's a kinder and gentler approach. In fact, I think I've heard that somewhere else.

I think our interest here is to learn more and to search for ways in which all of the stakeholders can benefit. I don't think that we're necessarily on an adversarial trajectory at all. I think some very good work has been done and is going to be discussed further today that represents a collaborative approach by stakeholders.

And I caution my colleagues in the regulatory sector that we need to observe a certain Hippocratic Oath in terms of not doing any harm as we move forward into this area. As a consequence, I do think transparency is a good theme to bring to these questions. Mr. Boyd?

COMMISSIONER BOYD: Thank you, just a couple of quick words, I won't elaborate as I did yesterday. I very much agree with your macro/micro view of things. Yesterday was kind of a B testament to the capabilities, feasibility and need for "call it what we want to call it." And we named yesterday DG generically, CHP, etc., etc. And I agree today is a little bit more of how to make that work.

So I look forward to that. I underscore your comments about collaborative approach, and the last decade or so it has proven to be the better way to go on so many things that I certainly agree that's the approach we need to take on this, and amen to transparency.

I know that's something that you have vigorously fought for in so many areas of this electricity arena, and an absolute necessity. So with that, thank you, and Scott, I guess it's yours.

MR. TOMASHEVSKY: Thank you, Commissioner Boyd. Good morning to everyone, thank you for sticking out a long day yesterday, for those of you that are here today and not sleeping in, we appreciate that.

Just a couple of housekeeping things. For your travel purposes, we are planning to be done at 4:00 today, and internally we've got some committee meetings that we've continued to postpone, so we do have a desire to get done by 4:00.

But that being said, what I said yesterday probably applies, so take that for what it's worth.

Also that we're being webcast once again just like yesterday, and the location of all the documents with the exception of a second presentation by Richard Seguin is posted on the website, and I'll have that at the end of this quick overview, which I won't say too much about.

But all those documents again are there, and we're looking at the same time frames for comments in this respect as well.

Just echoing on what Commissioner Geesman had mentioned in his opening comment, we are looking at a collaborative effort and we have been looking at this issue as a product at the end of the 2003 IEPR.

It does also fall into both PUC proceedings that started in 1999, which ended with the February 2003 decision, which looked at the system planning process criteria, and then also our desires to move forward on that particular issue as well.

So I just offer those two sections from the decision itself, which really, at least it determines what we want to consider within distribution system planning, and you can sit there and read the first part.

The second part is really the criteria that was used as a basis for utility compliance filings, which actually come out of the current proceeding. So just for reference, March 30th the utilities filed some updated distribution system planning criteria documentation in the first part of that language.

And that's also part of the posted documents that are on our website and probably will be some portion of the subject area that our utility now will talk about.

But you can see the four basic areas that our utility panel talks about. But you can see the four basic criteria, about being located in the right place, installed in operational time for avoiding and delaying expansion, looking at sufficient capacity to accommodate needs, and providing physical assurance.

So I'm sure we'll get into a lot of those topic areas as we talk about things today.

The agenda itself is not much different than what we had outside. There's a couple of changes, in least of people here. Judd Putnam will be speaking on traditional utility practices for utility planning instead of Wanda Reider, who we had originally.

And then, what we're going to do is we'll start with our distribution plannings discussion, so Judd will give us a perspective on what utilities typically do, and then we'll turn to Richard Seguin from DTE Edison. DT has been pretty proactive, at least in terms of how they use DG, within their system planning operation.

And it's really more from a utility solution. But he'll provide some insight as to what they do. And as he'll explain to you, it really comes from a top down approach towards how their company looks at distributed generation in the grand scope of things.

We'll have some Q&A like we've had with the various panels, and then we'll shift toward utility responses to that and some discussion of how they deal with their practices in the context of the March filings, and some responses and reactions to the practice issues that have been discussed before.

And then we'll shift towards some of the various research things we're doing with distribution planing methods. A lot of this is highlighting a lot of the things that we've been doing in the PIER program.

The intent of getting a lot of this R&D work into the policy directives, so we're using the research to come up with results that can then lead towards policy implications. And that's really where we're looking to go.

Finally then we'll end up with a discussion of the distribution deferral DG work that's been done in conjunction with both EPRI and Edison and turning it over to DTE again for some additional insight about structuring agreements and the like.

The summary of learning and challenges, we'll take that by ear and see where we are time-wise, but a lot of that discussion will occur in the context of the various sections.

And that's about it. Again, here's the web reference for documents that are posted, and we'll also, whenever written comments are submitted we'll also pos those as well.

With that, I guess we'll turn it over to Judd, and he can start with his presentation. Again, Mark and I will be co-conspiring on today's activities.

COMMISSIONER GEESMAN: Scott, is that an eye test?

MR. TOMASHEVSKY: That is an eye test. We were looking at the font above, but as yo know that size is probably not --.

MR. RAWSON: Judd, if you could come on up. Judd Putnam is a consultant that's been doing some work for the Energy Commission in the area of distribution. And we've asked Judd to come present today on how utilities typically do distribution planning.

Judd was in distribution planning up to his eyeballs, probably, in his previous career with a large utility here in the US, and he's going to step through this discussion for us this morning.

MR. PUTNAM: Thank you, Mark. This is

going to be a level sort of presentation, it's not exactly what we did where I worked and it's nothing that's done in particular at a utility. It is really basically distribution planning 101.

There are differences and unique processes at each utility, they're not all exactly alike, but this is the general process that's done.

I want to start out by saying that I've been in the distribution business all my working career, and I have termed it the vital link, in that it is the piece of the electric machine that we have that connects directly to the customer, it is the customer interface.

And in times past I have thought about the distribution system as a series of extension cords, because they're all radio circuits as opposed to network circuits in the transmission system. So, with that we'll go on.

On the overview of what is in this presentation, I think there's three things here that I'll really highlight. And that is that the purpose of distribution planning, and then the forecasting of the load, that is one of the biggest challenges that a distribution planner has. And then finally identifying alternatives to deal with whatever issues you happen to find on the system.

I was used to dealing with a system that had 3,000 feeders, and a feeder being a radio circuit. And of course those feeders had to be grouped and broken up. To do that then we based that around the substations.

And the purpose of that, after we had segmented them, was to identify loading issues that you need to have on those circuits. And in this presentation it says that the typical horizon forecast is ten years. In reality there's three of them, three planning horizons generally.

The first is the 12 to 18 month horizon, which is dealing with issues that are up front and imminent that you've got to do something about.

The second horizon is a five year horizon, which is for business planning purposes, doing preliminary work on any right-of-way or permit issues that you've got to deal with.

And then finally the ten year horizon is generally what rolls up for input to the transmission and generation planners.

So the purpose is really to keep track

of your system and what's going on. Back to defining those areas. With the number of circuits and the number of holes and the number of wires, the relationship between distribution and transmission is generally in distribution there are five times, at least five times the numbers of parts and pieces in a distribution system than there are in a transmission system.

In the planning process, because of the number of circuits, generally an individual planner is assigned a geographic area based on the substations around that. And then that individual's responsibility is to become familiar with that geographic area and the loads and what's going on in that area for understanding.

Then next step, of course, once the planner has defined the individual area, is to model that area, such that -- and modeling the circuit of course means knowing the length of the individual circuits, the conductor size, and the loads that are on that circuit.

And then in understanding the loads, the places that load information in the category that you know the best of is in the, is out of your data system, you system control and data acquisition.

You get information back on each of the circuits, and that's probably the best information you've got work with in the planning process.

So once the planner has the circuits defined and modeled and looking at the historical load the immediate past season and maybe for the past four or five years, he's ready to start collecting the other data or intelligence to make a load forecast.

Of course, the more information, the more intelligence an individual has, the better forecast you can make. But the sources of that of course are from your own internal folks, the people that are operating the system, the people that are designing additions to the system.

Generally, a large customer such as a shopping center, a hospital, any big incremental load has come through the planning department before that load is added. It's unusual to be surprised by a shopping center going in somewhere.

So the planner will also know about that, and factor that in. Your cities and your county governments often have economic development organizations, and they can supply some input on what they see coming down the road, and the confidence level in that.

This maximum land use thing is zoning. Planners pay a lot of attention generally to the zoning and zoning changes, because they could have a big impact on what the demands on the system will be.

Logo trends of course, home starts, and that's, I think, if there are other planners and planning organizations in the group, that's what we've been dealing with in the past 10 or 12 years a lot is the number of home starts.

And the last thing is the correlation of the system information forecast and understanding, once you forecast for an individual feeder then you need to correlate that back to the substation transformer and ultimately then the substation transformers are correlated back for a forecast on the system demand.

That's with all the information in place, that's generally all you're going to have. And you're going to have, the quality of each segment of that will vary from time to time.

And then normalizing for weather, that is again a big variable. As you load that you want to look, have you had unusually high weather seasons or unusually low weather seasons in the past few years. So that will influence the judgment of what you project the load to be on that into the future.

And of course the bottom line is you're going to have to take into consideration the capability of your system in a weather extreme season, whether it's winter or summer, load season.

Now that we've gotten to that, one of the really important things is that, especially when you hit multiple planners with multiple areas, is to ensure that they're using the same criteria to evaluate their feeders.

Today I don't know of software that would let one person be responsible for evaluating all the feeders, so you've got to get some consistency across the planning process. And you develop this criteria that you base your evaluation on.

Two influencing factors is current, you can only put so much current through a wire or circuit, and secondly, especially on a distribution I think because there are regular and independent circuits, they are really subject to having the voltage deteriorate and get down below acceptable service levels at the end of the circuit, because you've only got one point source feeding all of it.

So current and voltage are big criteria that you set, and then the last is contingency. How flexible can you make the system to recover from an outage incident or an outage event? Do you have the flexibility to restore the service by switching, or are you going to have to restore the system by repairing the damage, whatever that may be, a broken pole, whatever.

There are some tools today, and they've been around for awhile, to help this analysis process. The commercial software, and these are software tools, you load all the information in, you load in your assumptions, and that software will analyze that segment of your distribution system.

There are some that are commercially available, a lot of companies have developed internal software packages to do that. But I think with the trend to do away with the mainframe, and most of those analysis programs are on mainframes, but the mainframes are going away, so people are beginning to look for distributed software.

So, to this point, we've gathered all the information that we can get on it, we've analyzed our set of feeders if I'm an individual planner, I've applied the criteria and identified circuits that have potential issues on it.

And now it's time to say, okay, I've got these issues, I've got what I think is the worst issue and I've got a least issue somewhere, what am I going to do about those to correct them, what are the alternatives.

And that can be a long process that takes a lot of time. I can't say there's really a science to identify these alternatives and evaluate them, it's an art that you develop over time, because there are so many possibilities that you can have to solve the problem.

But I think out of this list what comes to the top is performing an economic analysis on the viable alternatives. Said another way, what's the least expensive way that I can solve this problem and get through it? And that's certainly a forcing function on that.

And then, down at the bottom, is managing the risk of the load forecast uncertainties. This is a forecast, it's a guess. Hopefully a well-informed guess, but when you're dealing with 3,000 guesses on individual circuits some of them are going to be wrong, and you may have to deal with the risk on that.

The alternatives to spend your resources to fix the problems, this is ann interesting concept, the SAIDI on that curve represents one SAIDI value -- SAIDI is a System Average Interruption Duration Index -- and let's call it 80 minutes.

You can spend your money by picking up feeders and substations over on the left of this curve, and maintain your savings just simply by putting adequate capacity in that you don't need much flexibility.

On the other hand, you can spend on configuration, which means you can build tie lines and install switches, so that when an event does occur you have the flexibility to go to the field and restore service by switching as opposed to having to go to the field and repair whatever's damaged.

So that's two ways to look at how you would address the issues.

We've got our forecast made, we've got our issues identified, and we have evaluated all the alternatives to solve the problems. Now we can begin to prioritize what issues we're really going to address, and this goes back somewhat to planning criteria.

Ah, these are numbers, I wouldn't venture to say this is uniform across the industry, but obviously if a substation is greater than 110 percent overloaded on its nameplate capacity, something should be done.

And by the same way, if an individual feeder circuit is overloaded 120 percent plus then that falls in the must do. And these are the items that need to be addressed before the next load season.

When you get down to the yellow, those things maybe show up on the five year forecast, and over time, three, four years out, maybe the ones that are yellow today may evolve to the ones that are red in 2008.

So it's very seldom that you get a feeder circuit overloaded, or get in trouble from a load standpoint, it's been my experience, in one year. You've been watching that figure over a period of time and it's in trouble.

So that gets down to the final prioritization and approval of what you want to do. This is just a representation of the dollars on an annual basis that we have typically been allocating to distribution capacity improvement, which is different than adding customers to the system.

You add customers so long, and then you have to do some infrastructure work on the distribution system. And I would add, I would invite you to disregard the numbers on that, but the point here is the inconsistency from year to year on the funding levels, which has been a challenge.

And that's a challenge to the planners, and I'll go to the planning challenges.

Obviously, the load forecasting data, getting accurate load data, and aligning the load forecast. And then when you get down to the bottom what you forecast as a planner is going to impact or substation and transmission upgrades, they should.

Given you have a list of your preferred alternatives that you want to take action on, either before the next load season or certainly begin to plan in the five year plan, the five year look of your planning, the planner has to deal with rights of way.

And you have the public street to use with the distribution system. That is not a guarantee that you can use that public street, in a lot of cases. You're going to run into community resistance if they haven't had a pole line down their street, and they're not interested in having one. So a lot of effort goes into that.

If the system is heavily loaded you certainly run into a challenge of getting a time when the load's down to take the clearance to do the construction. It's not that you can just say "I'm going to build this and let's start next Thursday." There's a lot of coordination with the operations folks that has to be done.

The planners generally don't have direct control over the construction, so they have to stay right behind it to assure that the project is completed by the time it's needed. In the case of a summer peal probably the first of June, in the case of a winter peak certainly by Christmas time.

And oftentimes the responsibility for selling the need to do the job falls to the planner, because the planner best understands what the issues are around it.

Additional challenges. Automation might come along, and the questions we ask the planner, considering that automation is an alternative to solving your problem, how much would it cost?

The contingency analysis, some projects are not going to get funded, and if the project doesn't get funded how are you going to deal wit that overloaded circuit if you have a bad peak load season, a bad summer or winter, and if an outage occurs?

That's part of that risk. You may go completely through the load season and nothing happens and nobody knows any difference. But a lot of the planners do, they sweat peak load seasons terribly.

It could, and we're going to hear another presentation on incorporating localized generation, that may be an alternative that they can consider from time to time.

And then the last one down there is the

internal coordination for technology deployment. Adding technology and automation really impacts the planner, because that changes all the rules that he's been working under for system protection coordination, assuring public safety, because the system's going to operate differently.

And then selling automation to the folks that have to operate, to get their confidence in it.

Additional challenges -- and this is just a day-to-day thing, and I don't know if I've made, I think I failed to make the comment that distribution planning is a full-time job, it goes on year 'round. The distribution system changes day to day.

Even when you get a plan for a 12 month outlook, in three months it's not going to be the same as it was when you put it together, because fast track load conditions, things change in a hurry, changing characteristics of existing loads.

You may have a bustling shopping center, and it closes. Well, that load goes away. Meanwhile, you have done the effort to do the planning to accommodate a new Nordstrom's for that shopping center. But instead of adding

Nordstrom's you take the whole thing away.

Well, from one standpoint that's a good thing. That feeder circuit no longer has the potential to be overloaded, but obviously you've lost the load on that.

There is a strong tie between the planners and the system operators. Some companies will put the planners in the operations group during peak load seasons. A planner knows every one of his circuits very well, and knows where the weak spots are.

And when something happens the operations folks can rely on that planner to help them make decisions on how they're going to shift that load around.

So, there is a lot to it. That's kind of Planning 101. It's a year 'round process. It is not an exact science, by any stretch. There's a lot of judgment goes into it. There's not one solution, even for one circuit. There's always multiple solutions and you have to evaluate those solutions and pick the best.

Lately the driving function has been the least costly solution to that. And your work, in conjunction with the rest of your planners on the distribution system, constitutes a low projection for the system coming out.

And of course it's focused on individual circuits. That individual circuit lives in a world of its own. ?The only impact that circuit has on the adjacent circuit is when something happens and you have to start shifting that load around to an adjacent circuit that does have enough capacity to take care of it.

That's my distribution planning 101. Are we taking questions?

MR. RAWSON: Yes, I think before we have the next speaker, are there any questions on Judd's presentation, we could take a couple of questions now.

COMMISSIONER GEESMAN: Let me start with a couple. On the chart that you had the different color code of priorities, you had different thresholds for feeder investments and substation investments.

Could you explain again as to why those thresholds are different?

MR. PUTNAM: The substation will be serving, typically -- well, let's say the substation transformer, typically feeds four feeder circuits coming out of it. It's bigger, it's a big device, there are definitely loss of life issues if you operate it above that level.

A feeder is, as is going to be said later today, it's sticks and wires, there's not as much of an investment in that if you do damage it.

COMMISSIONER GEESMAN: In a utility with 3,000 feeders, how many planners do you have?

MR. PUTNAM: We work with about 11 or 12, so it's typical that a planner can take of 300 circuits, because some of them are going to be real high growth, some of them are going to be static, and some of them are actually going to be a declining load.

COMMISSIONER GEESMAN: And are these planners usually at the headquarters or are they dispersed out in the field?

MR. PUTNAM: The trend is to centralize them. In the past, I'd say up until the beginning of the 90's, I'd say they were geographically out in the districts. But as the need to be more consistent across the company, apply more rigid criteria for these upgrades and that sort of thing, they have more and more become centralized in one office.

Let me add to that, it was my experience, and it was the way I put the challenge on the planner, is part of their job was to be intimately familiar with the people in the day-to-day operations in the planning area that they were responsible for.

COMMISSIONER GEESMAN: Is there a common professional discipline? Are they electrical engineers, or do they come from a variety of backgrounds?

MR. PUTNAM: They can come from a variety of backgrounds. Because it is an electric utility the bulk of them are electrical engineers, yes.

But planning, it's sort of a business issue in terms of gathering information and making a forecast. I had in my organization a nuclear engineer, and he was a great planner.

COMMISSIONER GEESMAN: Thank you.

COMMISSIONER BOYD: If I might, first let me thank you for that education on distribution planning 101. For some of us, in particular, it's good to get down in the trenches for a few minutes with the folks in the field and understand what it is they have to do.

I listened with interest to that, as I'll put it, historical overview of the way the process is carried out. And you did mention, we're going to hear shortly from folks about how -- and you used the term localized generation -- can get into the planning process.

But I wanted to ask you, looking at it in kind of the way you described it, the conventional planning process, do the planning parameters that planners operate under either facilitate or even allow thinking about localized generation as one of the regular ways of addressing some of these issues?

MR. PUTNAM: Yes, sir. If you have in place a, I hate to say standard, but a uniform way to apply distributed generation, that could just be another alternative. You'd have to establish the parameters under which distributed generation would be applicable as a solution, I think, to get some consistency around that. But that can certainly be done.

It can be a component of the planning process like automation or sticks and wires.

COMMISSIONER BOYD: Okay, I appreciate that it can be, but is it fairly routine now, or are we just on the threshold of making it perhaps part of the process?

MR. PUTNAM: In my view we're on the threshold. Where I was we considered it for a few years, tried to establish some parameters under which it could be used and use it, but the technology at the time just didn't pan out, either economically or from an environmental standpoint.

But with better technology, and addressing the environmental issue, it is a viable alternative.

COMMISSIONER BOYD: Thank you.

MR. PUTNAM: Thank you.

MR. RAWSON: Any other questions?

MR. CONTRERAS: Hi, I'm Jose Luis Contreras from Navigant Consulting, and my question is are there any performance objectives that planners need to meet, and is there career advancement for compensation types, meeting any type of numerical objectives?

MR. PUTNAM: That's an issue with all engineers, be they designers or planners or standards folks. Incentive compensation, no, I'm not aware of it. We haven't advanced, at least in my view, in the utility business to get to a level where we can have individualized performance incentives for folks.

We have been working under group incentives for a time, but we're not individualized.

MR. CONTRERAS: Those group objectives or incentives, what things are they measuring?

MR. PUTNAM: The measures were, and I think they still are today, the performance of your system for reliability, your O&M numbers, and of course safety.

MR. CONTRERAS: Thank you.

MR. RAWSON: Thank you, Judd.

MR. PUTNAM: Thank you.

MR. RAWSON: I think we're going to shift gears now, and we're going to look at Detroit Edison's approach to incorporating distributed generation into their planning process. But before we start with the formal process I think we'll do a video here that Detroit Edison and DTE Energy put together on how they look at distributed generation as a distribution asset.

MR. TOMASHEVSKY: And I just wanted to add, just for those that might be visually impaired, actually, we have a limitation here of our technology. We like to push a lot of buttons here, but the image up here will be pretty blurry unfortunately. The image on the screen should be fine.

And it's just the fact that we don't have a DVD Rom that's connected to the system.

(video is played)

MR. RAWSON: Okay, with that introduction, I'd like to have Richard Seguin, who's a principle engineer for the distributed generation program at Detroit Edison and their affiliate, DTE Energy, come up and give us a presentation on how they've incorporated DG into their planning process.

MR. SEGUIN: Good morning all. Any questions on the video at all? I heard someone say it was a commercial, and indeed it is ia commercial. I mean, we want to be successful at rescuing an overloaded circuit at at substation.

And the first concern that everyone has is for the noise, and then the environment, and I can stand up here and wave my arms around for a half hour and get interrupted by people who just want to understand the process, or you can produce a video that hopefully that keeps them from interrupting the video long enough to get the whole message out.

And it's eight minutes and I think it's very effective. We did it originally with our home video camera and it was kind of cute, and our digital department said let's make that -- particularly with digital video today, it's not that hard to piece together a little story like this -- and we did.

And I think it's effective, we've had a lot of good comments on this, and I think it's helped us bridge the gap with customers and community about why we need distributed generation. It gets rid of some of the myths and helps you move forward. There was another question?

MS. SHERIFF: Good morning, I'm Nora Sheriff, I'm here on behalf of the Cogeneration Association of California and the Energy Producers and Users Coalition.

Here in California we're concerned with critical heat pricing periods and meeting peak demand, and it seems that you're using this to meet peak demands, you know, seven to nine days a year.

And I guess the question that I have, I realize that you're using it as an interim solution before you can implement the wider solution, but how much does that cost?

MR. SEGUIN: It costs whatever diesel costs. We have nuke, and we've got a lot of coal. Nuke's about $8, coal somewhere at $16 to $20. I don't know what diesel price is, it's about $100, $120 a megawatt hour, so that's the ratio.

We're not doing this for generation, we're doing it for stick and wire. Let me give you an example. If you're concerned about not selling during critical time and losing a part of your income, if we outage the whole circuit, you know, 16 MBA, that's 16 MBA less that a generator has to serve.

We';re putting in one or two megawatts to keep that 16 MBA on line. Or maybe, instead of it being 17 it's 16, but our choice might be zero or 16. Does that make sense?

Because we have an excess of generation -- or is it lack of customers, I'm not sure -- there's a story behind that. But we consider it distribution capacity. It's not generation for generation's sake.

Because we own generation also, we don't get a nickel more off the meter because we generate with $120 versus $8. We want to run this absolutely only when we have to, and you'll see that we'll do it when the circuit needs through remote control.

MR. RAWSON: Let's let him get through his presentation, because I suspect he'll answer some of your questions, in the interest of efficiency.

MR. SEGUIN: Okay. I always have too many slides, so I'll try to go through them as fast as I can. The must for distributed generation is integration into the planning cycle and requires management support, not just lip service for it.

And I happen to know some folks who play with batteries let's say in the guise of doing something for distributed generation, but I'm not sure a battery is going to solve the energy crisis if there is one.

You must be a dedicated group to champion DR, not just a group there to handle interconnection stuff, but to present it as an alternative, educate other distribution planning engineers, and manage the products. These are stick and layer folks, they're not necessarily generation kind of folks.

We've been building generation for a long time, but those were the generation folks. Now we're looking at stick and wire folks doing distributed generation and it's not, you know, it's funny, we may have them at our garages as backup for our own homes but when it comes to them at work we just kind of don't know what to do with them.

And I think you need one central group to get it kick-started. And then what I'm doing right now is probably the single most important thing, is the communication. Because people are, well, what does it sound like.

I'm going to them for underground design and the first thing they want to do is they want me to talk about, well these are my own quotes. Communicating to your planning and engineering and construction and operations folks is the single most important thing -- why are we doing this, what does it cost, and what are the benefits.

And once they get comfortable with it we find that they find new ways to use it, and better ways to put it together.

So I'm going to give you some background and vision, which i think I probably already have, of how we integrated it into the planning cycle, to answer the questions from earlier, how can you get it in there. And then talk about some distribution solutions and premium power.

This is Detroit Edison's service territory. I'd like to mention first off, there's DT Energy, which is the parent company that owns a gas company, an electric company, and etc. Detroit Edison is the electric utility in there, it's a distribution and generation company. We just recently sold off our transmission.

It's about a $12 million company, distribution, sticks and wires and substations make up about half of that, about $6 billion of assets.

What's most interesting is we have a very large industrial database, customer base, with the big three. And about 12 percent of our load is covered by generation already out there. It's a big hunk, if we could somehow capture it, if it's in the right place, borrowing a line from

Tom over there.

So here's our commitment, and when we talk about starting at the very top, the CEO and Chairman with a statement like this, you know, looking for a vision for the future, seem parallels between the computer industry and the utility industry and I think we're going to go to the laptops.

I think we're going to go more on reliance with distributed generation. So our vision -- actually that's his way, this is my way. Imagine that you as a utility person, with a truckload of this new DG technology started up and headed towards you, what I see are three ways we'd typically deal with that.

One, we'd throw ourselves in front of the truck and hope it stops, and I see smiles so we also know some folks who do that. Engineers being the kind of smart people they are, they won't do that, they'll run out and grab on to the back bumper, drag their feet hoping to stop it or at last slow the darn thing down.

And then of course you can jump up in the cab and help to steer the direction of it. And that's what DTE wants to do.

So we see it as, you've got $6 billion worth of sticks and wires, and it's going to transition to $6 billion worth of sticks and wires and a little bit of distributed generation. Does that make sense? It's just another tool.

We solve problems, don't we, with capacitors? Do we solve every distribution problem with capacitors? No, we don't. It's just a tool.

I tell a story about a shovel and a trencher. You know, we used to dig all our holes with a shovel, and then we created a trencher. Now we dig all of our holes with a trencher. Now we use a directional bore, what a great way to get under the road.

Do we dig every hole with a directional bore? No. Most of the work is still done by the sticks and wires, the trencher, right? But when it becomes time to go under the road, there's the directional bore and you're glad you've got it.

And now you see the parallels with distributed generation, it's a specialty tool, it has its place, but it's not the be-all end-all.

And of course the big thing is to start a group that will be responsible and champion it through the system, responsible for more than just interconnection.

Integration of the planning and operation cycle. Well, first off you got to get rid of the misconceptions. These are somewhat broad, I have a list that I've added on this that's a lot longer than this. This is from Mark Osborne of Portland General who has been doing some stuff from a generation perspective, I guess he couldn't be here to speak at this.

But it's too expensive, well, maybe not, we'll take a look at that. It's unsafe, Scott, it just takes some more looking at that from a protection standpoint, and etc. It's not new and scary, the utility's been doing generation for a long time.

I've been a planner for three, four years at Detroit Edison. And it looks like it's no longer about just solving overloads and low voltages anymore, it's about making investment decisions and quantifying our distribution solutions in investment terms and communicating them typically to non-engineering folks that control the budget.

All this at the same time our capital

budgets are going down, our customer expectations are going up. A planner now has to balance the need to add new distribution with caring for that 6$ billion worth of existing stuff out there. He's only got a limited budget and he's got to save some of it for both ends.

And that's why we feel we can no longer afford to solve every one MBA shortfall problem or criteria violation with a 30 MBA type solution, a new substation.

One MBA problem may only occur a few hours per year, $100, maybe less. And a 30 MBA solution that may not be fully utilized for several years, much like the example of the shopping center that closes. What happened to that capacity?

We believe that DG is a way to time that going in with smaller chunks of capacity addition, where you're waiting for the real deal to occur. And perhaps most importantly, freeing up those dollars to spend on the $6 of assets that have customers already attached that need some infrastructure here.

So how do we do this? Well, we can take a look at the capital budget. This is Detroit

Edison's capital budget for 2003 projects. Here are all the projects, I just arranged them at increased cost.

And this is their cost, their capacity divided by cost, giving me a cost per KW of standard T&D solution. And this is the capacity added, not the criteria shortfall.

And these are some numbers I threw up to be a guide to our planning engineers that when you should consider using DG? Well, if you consider just the capacity, sticks and wires are way too cheap for generators, way too cheap.

I didn't put it on here, and probably it's about $159 of KW is Detroit Edison's cost per distribution. That's not throwing everything in there but the kitchen sink, because we beat the snot out of all of our T&D alternatives. That's part of our process, operating in a minimum capital budget, is we, there's no extra fat in there if we can help it.

And if you add the maintenance part of that, the capital reliability, that gets a little bit over 200, maybe $210 per kilowatt hour. How am I going to do that with a generator? Can't do it.

However, if I go to the next slide, if you examine the criteria shortfall divided into that cost you get a different kind of thing. And there are two kinds of things that we see here.

Number one, and perhaps even most importantly, is where you don't look for a DG solution. Remember sticks and wires are really cheap? And if we've done a good job most of these things here are cheaper than DG anyway, so why would you waste your time, planners are busy folks -- and it's a year around job believe me, I've had it for a lot of years -- you only need to look at those where the cost to solve the overload is very high.

And indeed that's how we present it to our planning folk. So here's an example, if we, adding 10 MBA capacity for $1.5 million, it turns out to be $150 a KW. If it was only a two megawatt shortfall that would be 750, you see that?

So, planning definitions, you can read these. I like to think about it as, from the video standpoint, everything is emergency, temporary, and permanent, okay.

Emergency is kind of like, help me get

it done. Temporary is cut me some slack. Permanent is, okay beat me up, how many copies of the planning review and elevation surveys and etc. do you need for this?

And I try to get that out to our Department of Environmental Quality, the Public Service Commission, the community and the customers, to let them know these are different levels of planning here, there's different levels of response, particularly when it comes to distributed generation.

So where can you use DG? Well, you can use it for maintenance, we've done that, idling whole substations on generators in emergency obviously. You put in a generator to help avoid an outage.

Temporary use, or for DG and defer or, you know, because we can't get our work done, which happens quite a bit. We sent our crews down to Florida four times there last year and, you know, toward the end -- these are contract crews, we don't have that many crews that are direct to Detroit Edison now, we contract that out.

And it got close to winter and guess what, they all stayed down there, they're paying them lots of overtime, and we can't get all of our work done.

Now you probably didn't have that experience, but it happens on the other side when we have a bunch of storms.

And one of the other things for permanent is to, we've done this service for customers, maybe a permanent way to do that, or replacement of old generation.

If it turns out that there's, the new generation, the new Clean Air Act is interpreted per plant we may have to put some distributed generation on the sub-transmission because we've got 100 megawatt that we use for reliability a lot to cover contingencies and shutdowns that's going to need to replacement.

And we think we can replace with 60 to 80 megawatts of distributed generation, mostly connected in the substation. We hope it doesn't. That was the only plant that stayed on during the August 14 blackout. And they operate on a shoestring I might add. A good coal plant.

So who can own these things? Distributed generation. Well, we think the utility can own it, particularly if it's considered distribution capacity. It could be a utility/customer joint partnership, and we're doing some of that with our premium power program.

A customer owned DG where you might lease it. During Y2K a lot of water boards pulled a lot of generator out there. If it's in the right spot over there, Tom, maybe we can make benefit of that, right.

If you need the generation it may not be a bad idea if you have a generation shortfall to tap in to some of that unused asset, and we're doing that with our water board.

And then customer interruptible. There's megawatts and there's megawatts, right? If you've got a problem there's nothing wrong with megawatting some of the problem, right.

So, engineering solutions versus the budget. We've got this new tool, we've got traditional sticks and wire and we've got new tool DG. We're going to defer capital, reduce the budget, free money for other projects, solve some other problems, optimize manpower or conserve resources when we don't have the crews to do it, right.

So let's consider distributed

generation. Let's take a look at the typical project plan. Following all the typical project planning 101 that we heard from earlier, let's just look at it a little differently. Let's do the project.

Let's actively try to use DG to divert the project and avoid -- . And then do nothing, and this project is probably not going to be funded and the worst that happened, you know, you get caught and you rush in with DG and other things to put the system back together, right.

And this actually happened, that's how we got started originally. So let's take a look at building a new substation for $6 million, let's look at DG cost.

It turns out that we had to do this, and we captured the cost, the $280,000, we were outaging, we had 27 days in the 90's and we were outaging the customers every day. They gave us permission now to build the substation but we couldn't do it overnight.

So we put in, we leased the DG, put it in there and retroactively, after it was all done, we looked at the cost of leasing it, which we paid almost 25 percent of the purchase price of the generator just in lease costs.

And looked at if we had proactively done that. Let's take a look at a little NPV trip down there. Let's look at cash in cash out. Here's doing the project, and you get an NPV here of .73.

If you would defer the substation with planned DG, where you went out and bought it at an annual cost of $32,000 as opposed to $120,000 of lease cost, and look at it that way. Or just the burn down alternative, do nothing, and the way we did it and what the costs were.

And I guess most importantly, I mean, you all have different NPV models and stuff to look at there, but to look at it in three ways.

And it turns out here that, if you take a look at traditional, both the DG alternatives, in this one case, it was favorable to do the DG. We white knuckled it though, and it wasn't good for us, and we broke some tagging safety rules with our substation out, but it was our first time we ever did DG.

But it was this lesson that taught us, maybe we need to buy one of these and use it like a portable substation.

Okay, so how do you develop a capital

budget? Well, here's how I do it. I have current year, we call them lights out project, you know, an unanticipated problem, or current year projects that can't be done. Our crew stayed in Florida, we can't rebuild all that wire.

Probability analysis of not completing future projects. You need to make a list of all your projects that are scheduled due for next year, and you assign a probability of chances that it's going to get done.

And you go to your project management folks and say "which one of these won't?" There's one golf one that we've got, and our project management said 100 percent chance it won' be here next year, right-of-way, we've got wetlands issues.

So I need one generator next year. It turns out I've got one coming out of another place, so I can use that one. But I'm using that probability analysis to determine my budget, and do I have to plan on putting one in and taking one out, number one, and should I buy another one. It seemed like a good way to do it.

And next year's budget cycle, we call it project value analysis. We go through anything that's a million dollars or more and take a look at it. And I'm sitting there on every one of these, and you know, when I raised my hand is there another alternative? You know what I'm saying. Actually, I just raise my hand, they know what I'm going to say.

But at least to start them thinking about DG and how it could be used. Is there a big customer we could partner with there? The load causer, if you will, let's partner with him.

And capital projects not funded. Here is planning on a constrained budget. We never have enough money. You all have this. I guess the tough one here is the cut the least critical projects. It's easy to say, it's hard to do. Those are places where you're going to get hurt.

So what are the must-do projects? Well, safety, regulatory requirements, relocation, you're in the road right-of-way, you've got to go, there is no other alternative, you have to spend that money.

And then discretionary. Reliability with Public Service Commission penalties if we don't do it. You remember that $6 billion in assets. We've got to save some money for fixing it up and trimming trees and stuff like that.

What's left? Overload, yes. We take a chance. So which projects do you cut? Well, we look at a way of cutting them by risk. We'll take a look at three projects, each having $300,000, right.

And take a look at the cost, run some failure, and see what happens. Here's one where we have to pay overtime and etc., and at risk, if we wait, was only $24,000. We let the cable burn out and went in and put in a new one, and we spend some overtime to do it, right?

So that's very little risk. I'm in favor, if I'm not going to do one to not do that one, right.

Here's another $300,000 project, where we re-conductor a portion of a poor performer, right. Our cost at risk there is $116,000. And here's another one, where I'm going to replace a transformer.

Only here, if I've got to pull in a DG and do all this stuff, I didn't like to working out so that DG was the one that you went ahead with, but it may indeed be that.

And if you look, this is the least

likely one to cut, the other two you'd cut in a constrained budget.

And that's how we try to take a look at that, and we try to take a look at it particularly in the do nothing, where DG is part of the alternative of the do nothing when it makes sense to do it.

I think of it a different way, I think of my President just trying to get more money out of the controllers by saying a catastrophe could happen here, I really need the money to do this project. If you think about it -- should I be saying this in front of you guys -- DG can be an asset in getting you more money to do critical projects too. I mean, it could be.

Here's some of the stuff we've done. We've done a number of different projects since 2002. Islanding and maintenance up in here, some temporary and some emergency installations. Do I have pictures of the stuff?

Yeah. This was our first one, that's the one where, this is actually a substation we bought and they wouldn't let us build. It's across from a library and they're worried about fuel effects on the children. They built it right on top of a 120 double circuit power line.

But when we started outaging every day, not on purpose, honest to God. It turned out this was our first four days get a generator in experience, and it worked. And we just started making things better.

Oh, one of the things I say is just buy one and do it, like a portable substation. How do you justify purchasing a portable substation? I mean, do you all have portable substations? We do.

And you pay for that portable substation every time you use it? Le me give you an example. You have a transformer, and you can change it out. One of the examples we looked at was changing out a transformer to -- it's a single tap transformer, so you pull in a portable substation, right, to take the load off the transformer so you can change it out, and you put the new transformer in.

So, do you capitalize the cost of the installation of that portable in and out? Yeah you do, it's part of the project of changing out that transformer. So it's a capital cost.

Do you pay $800,000 or a million dollars every time you use it someplace? No, it's a cost of doing business. You bought that one portable substation, use it.

And I see the distributed generation rates are much like the portable substation, except for it brings the generation with it. It's not as big as the portable substation either, you only get a megawatt or two out of it.

And if you've got, we have some residential areas where it's all residences. Where could you put a generator there?

First, they're up against the lake, so how do you put a new substation in there, how do you bring new lines in? Well, where would you put a generator.

And these are 60 foot lot homes, you know, all three bedroom basics, they've added a second story and now have all air conditioning and five TV's that never turn off and that sort of thing, so our three and a half MBA 4800 circuits are now tipping up to five.

You get three days of 90's in a row and it's six. Well, you know, what residential area doesn't have a high school. What residential area doesn't have a church. As a good corporate citizen, what's wrong with partnering with a school or a church?

We have an ice storm up in the thumb of Michigan, because there's not as many of them, we don't put the wire back up as fast up there as we do in the city, and so they're out for a long time. And where do you think people went for heat and food and stuff? The churches and the schools.

It seems like a nice place to put a generator and have one there. For when they're not there and you are. Typically our load's not up on Sundays, so we're not going to bother presuming on their Christian faith.

And indeed we've done that in a couple of places in emergency. Part of taking this temporary and permanent emergency to work is you start convincing people, people know. And if you do a good job of taking care of the school board chairman -- the planning guide -- and you've got an emergency situation, we got permission to put this generator in in one day and they helped us find a spot for it.

Because the school board chairman said I could give this guy his phone number, because the Planning Commission told me I could give this guy this phone number.

We have confidence out there, and when we were there the school board guy came out and said, I think, some pretty nice things. He was happy with this installation.

You know, schools are falling on hard times. What's wrong with helping them buy some football jerseys or something? Nothing. We'd probably do it anyway, independent of this -- through our funds, right, but --.

And here's -- okay, I forgot this. Where do you put a generator? Well, you can put it in a substation or you can put it not in a substation. Here's a substation. To me it's not quite as effective, but how many people have islanded substations?

We had a substation on a long radio tap that was hit by a tornado, made temporary repairs, so a couple days later we've got to go back and fix the incoming line, which means we've got to go two ten hour outages, right, drain the resources from two other adjacent service centers, with tagging in and out it takes awhile to get stuff done.

Or we can pull in a generator, give them a momentary in and a momentary out, and not outage

800 customers. And that's what we did there.

And what's interesting about that is that was using the same lease generator that we had at the first installation. Our folks thought of a different way to use it. I'm not sure the engineers would have thought to use it that way. And in maintenance at the same time.

So, how do we do this? Well, when you're integrating the planning and operation process you've got to convince your operators as oh, God it's a generator what do I do?

Well, you've got to convince some of them you don't have to do anything. Fans on a trans phone, I equate it to fans on a trans phone. From an operations perspective, does the operator order an operator on to the substation to turn the fan off when the temperature gets up on the transformer?

And then does he call me and go back and turn it off because the temperature went down now? No, it turns on and off all by itself, right. The only time that operator really gets involved is when the darn thing doesn't work the way it's supposed to. He gets an alarm, the fans didn't turn on, better get an operator out there.

So we have used that kind of psychology on him to say let's do the generator that way. Your best times are when times are the worst. We want you there protecting the system, let us take care of the control to manage the load.

And here's our emergency rating on the transformer. It has a generator. And here's our day-to-day rating. What we do with this is we wait until we exceed by a little bit the normal rating and then we turn on the generator.

And this is the transformer's load, and we modulate within about 10 or 20 KW until it falls a little bit below the rating, once it's on, so you don't turn on turn off turn on turn off like that, and that's how we avoid an outage or an emergency situation.

And we've convinced our operation folks, and seem to like it, and it works. And we do it wireless. We jack in a portable ACM on the circuit and feed it to generators PLC until it's turned on turned off.

Premium power. Okay, we talked about us using the generator for distribution capacity, how about partnering with a customer? Well, we got this premium power program, I'll talk a little bit about it this afternoon.

But here's a situation where ACS, American Car Specialists, tier one automotive supplier, was going to add two megawatts worth of load. Well, it didn't meet our two times annual revenue test so they were going to have to pay $400,000 to upgrade a piece of wire that they were going to overload with their load condition.

We interested them in this premium power program, and give them standby, they could move to the interruptible rate and get 20 percent off their bill, and it saved them the $400,000 CIAC cost of upgrading the wire.

And we only asked that, we can turn it on to banish the loading on the wire if we want. And it's a standby for them. I call that win/win, and it's doing it with nothing initially out of pocket, using some of our interruptible rate system, existing tariff, to help them pay for part of it, and they get standbys. As a tier one supplier they're penalized if they don't deliver on time.

Listing of all known DG's and interruptibles. What we did here was, well, okay, if you wanted to get your folks interested in using DG, give them a list. So we did that.

Let me explain this a little bit. This color would be customer-owned DG. The blue is primary interruptible, that's our D8 rate for primary. And secondary interruptibles, our D33 rate. And then Detroit Edison owned generation is this color.

And we sorted it by substation circuit. See this circuit, L grid 8254, it's got five megawatts worth of generation. You can't get all that, and you may only be able to get the load benefit, but it starts your operation folks when it looks like they've got a contingency or loading problem it allows them to look down there and see how much flexibility they have, whether you own the asset or the customer does, whether it's megawatts or negawatts, to avoid a problem.

And we've done this in the past, particularly in storms, we've asked hospitals to turn off and on their loads for us and etc., and they've done that. So this is no different than the kinds of things we've done informally in the past, it's just putting it in a structured way so our operations folks can see it.

We also make it available on the website for our planning folks to see it too when they're planning. One of the single contingency things is what happens if the generator doesn't start? You may have some flexibility here, you've got an emergency rating, use it. You own the generator.

Okay, so here's our 2003 installations that we had. I guess I'd call your attention here to this one, Grosselle, that's that school in-between the junior high school and the high school.

The cost of that project is $3.8 million. We had 26 hot days in 2002, two days in 2003, three days in 2004. The loadings that we had, they were 45 hours, three hours, and 40 hours. So the load is there, it just kind of depends on temperature, and it is growing.

What's eight percent, we save $312,000 for two years and it cost us $70,000, including the purchase of the generator and the installation. Purchase, annual cost. I'm going to pull that up and use it somewhere else after the five year lease period, right, lease with the customer property.

The bottom one, here, is I moved one that I previously purchased in the emergency situation, to build some wire up there to take the load off so I didn't have a problem with $180,000. It cost me the annual cost of $15,000 to relocate -- remember the portable substation idea?

All I'm doing now is paying for the relocation and removal of that previously purchased DG and associated connection equipment.

No magic there, 8.2 percent times the cost. I mean, I didn't go in to all the NPV things with it, but that's just straightforward taking a look at annual cost.

Okay, so in summary, I think it's really important that you have management support. I don't know if you can tell by those slides, we've done an awful lot in the last two and a half years, and we wouldn't have done it with -- unless we got our backs into the wall and got lucky the first time -- and we had management support.

From the top down we believe in distributed generation, and we're one of the founders of plug power, right. And when did we do that, in 1998, something like that. And in four years -- I hear it's five now -- but we're still trying.

However, this is a little different kind of trying. It's the kind of trying that's putting iron on the ground. Now, I know you folks don't like diesel, it's a nice way. We're ordering up a new one.

But consider emergencies. I also went to graduate school here for environmental, and they have this thing they call total environmental quality and it's where you draw the box around the whole problem.

Now if you outage these folks and they go into their garages and they turn on their gas generators, if you were to look at what's going in the air at that time instead of tightly controlled DG that you would have, diesel with blended fuel, with natural gas, and you get that diesel out there as quickly as you can and you bring in the natural gas later, right, to blend the fuel.

If you look at the impact on the environment, which would be worse? And I think it's just another tool. I'll go 37 projects and one, two is a DG thing. I mean, sticks and lighters are where it's at for the foreseeable future, until it gets cheaper and until it gets cleaner and etc.

But it does have a place, it's small,

and I think it will grow. I guess that's all.

MR. RAWSON: Thank you, Rich. We're going to have questions, and I wanted to offer up front first.

COMMISSIONER GEESMAN: A couple of quick questions. One, I see that you've got portable units. Have you been conducting your program long enough to have actually moved the units around?

MR. SEGUIN: Yes.

COMMISSIONER GEESMAN: So there's not a risk of these becoming permanent solutions in a capital constrained environment?

MR. SEGUIN: Well, it is true that we've extended lease on two of them. However, we have moved also.

COMMISSIONER GEESMAN: I'm a finance guy, so I, I had the sense that --

MR. SEGUIN: Well, part of that, there's a good side to that, not necessarily a bad side. The good side to that is your planning engineers see that the problem is solved, and they can see what the load is.

Now, we've got to be careful, when it gets hot, and if we have two and three and you're supposed to have 12 two years in a row it could be a bad year for us, but they're at least thinking now in terms of DG.

I can use that money somewhere else now on something. You know, you can't always afford the best deal. Let's say for instance you've got two bad tires on your car, and $75 apiece. But the tire stores have it four for $200. And all you've got is $200, and little Billy needs a trip to the orthodontist, okay.

Can you afford the best deal? It's going to cost $50 for the orthodontist. I have an idea you're going to take little Billy to the orthodontist and buy new tires. And that kind of similar thing, we're at least making them aware that that asset is there, and they're taking advantage of it, probably spending the money on more important things and leaving this off for the moment.

We leave it on wheels. I think that's very important, as a commitment to the community and the customer, as a visual sign this thing is temporary.

COMMISSIONER GEESMAN: Right. Second question. With respect to utility owned equipment on a customer site, we've heard a lot from private businesses that they don't want to be dependent on somebody else's machine, or they don't want the utility in their plant.

Do you find the public sector or non-profit sector potentially more receptive to partnerships with your equipment, or is there any difference?

MR. SEGUIN: Well, there's two kinds of our equipment. There's the equipment we're using for distribution solutions, and then there's the equipment we're partnering giving standby to the customer so he's enjoying benefit and a load relief for ourselves.

In the case of the former, where we own it all and he's deriving no benefit, he is deriving a benefit. It's like with Mark Osbourne's slides, if I could page back to it. If it's worth their while they'll like it. And it's a matter of making it worth their while.

COMMISSIONER GEESMAN: Fair enough, but if I were an entrepreneur within your department would I be better off focusing on your schools and city halls and hospitals versus --.

MR. SEGUIN: Yes. Well, for more than just that reason. We'll continue, we're continuously, like the video said, looking for places that are out of sight and sound. So these people typically have real estate, and a lot of them actually have generation.

COMMISSIONER GEESMAN: Thanks a lot.

COMMISSIONER BOYD: I'm the air quality guy up here, and we're not afraid to say clean diesel in this state.

MR. SEGUIN: Yeah, it's all clean today, right?

COMMISSIONER BOYD: We're willing to look. I recently keynoted a conference on clean internal combustion that was co-sponsored by us, the DOE, and the South Coast Air Quality Management District, the real bad guys.

MR. SEGUIN: Is that the tough one, that's the --

COMMISSIONER BOYD: That's the tough one, yeah. We're not totally blind to the idea. Just a comment.

MR. SEGUIN: Yeah, I think there's a lot of promise in this blended fuel stuff personally, where you could, if you truly do have an emergency, maybe you allow the diesel. But if it's going to be a temporary you bring in the gas.

And you can do things to make it pretty clean I think. And it's going to be there for a few years, you know, when you're trying to get out of a sticky summer. You can work to get the gas there, but the diesel is pretty easy to get it there.

COMMISSIONER BOYD: Great, although do we have a lot of gas in the state?

MR. SEGUIN: Oh, well, that's a horse of a different color isn't it?

MR. RAWSON: Any questions from the public? Oh, on slide 389, Rich, you showed some projects, which ones of those were diesel and which were natural gas?

MR. SEGUIN: Yeah, natural gas, natural gas, natural gas, diesel, diesel.

MR. O'CONNOR: Good morning, your presentation was terrific. We really appreciate it. I'm wearing my CADER hat today. Todd O'Connor, Executive Director of CADER.

Can you come back for our conference on September 7 through 9 and bring a regulator and bring a customer? We'd love to have you.

MR. SEGUIN: The regulator I have is perfect for California. He loves all this new stuff.

MR. O'CONNOR: Well, we'll work with your people when you come out here. We'd love to have you. Silicon Valley, there's a golf tournament. How can you say no?

MR. SEGUIN: Well, I play handball though, I don't golf.

MR. O'CONNOR: I'll find you a court. And on a positive question, you focused on peak load value of distributed generation and how it not only provides value for the customer but to the ratepayer from the deferral of what would be an upgraded cost on a distribution system.

Are you looking at areas where there's been an increased load on the customer side, in terms of additional baseload, and still some T&D benefits that can accrue to that?

MR. SEGUIN: Not really, at this point. Even though it looks, actually that is quite a bit of stuff, but it's really only in its beginning and we're trying to evolve it and I believe in incremental change, and this is pretty good --

MR. O'CONNOR: I'm not asking a rock the boat question, I just was curious if that may be on your horizon?

MR. SEGUIN: Well, no, but, in the case of that ASC it kind of was that way, but it was brought about because of an overload. We hadn't really looked at that.

Although in our project value analysis, where we're looking at adding the next substation or transformer, we are looking for big customers. We look first to who's adding the load, number one. And number two, what are the big customers in the area to go after for either siting or partnering.

It's, we're trying to make that part of our planning process, is to consider looking internal to the circuit for the customer and where he's at, how much load he's got.

MR. O'CONNOR: Thank you, appreciate your time.

MR. SEGUIN: And we're doing it for stick and wire capacity, not pure -- I mean, because of this Public Act 141 we've lost about 30 percent of our best customers through deregulation. So, like I said, that's the story behind we've got an excess of generation, it may be more of a case of we've got a lack of customers on the generation side.

MR. TORRIBIO: Good morning, Gerry Torribio with Southern California Edison. Just a question on how you work, how DTE and Detroit Edison, a regulated utility, work together. Does Detroit Edison buy the equipment and put it in rate base? Or do they pay DTE a fee to lease it, in other words?

MR. SEGUIN: Well, first off, DTE is the parent company. It's the chairman of the board and a couple of other folks. I work for Detroit Edison, which has a generation sector and a stick and lawyer sector. And we have unregulated businesses tiered underneath the generation.

For instance, I guess we're the second largest hauler of coal. Go figure. ?And we do a lot of biomass.

On the stick and lawyer side we've got our DT Energy Technologies, who originally started out on a SCADA project called the Intelligent Link, where we were going to try to control things internal to the house and stuff like that, pretty fancy SCADA stuff.

And it turned out that we decided to make generation. One of the generation projects is taking a GM 8.1 liter diesel engine and gasifying it -- and it meets 2007 California standards -- and bringing that kind of product to business.

So we use that DT Energy Technologies, were allowed to buy our Public Service Commission, to use them as our construction of the generation.

MR. TORRIBIO: Thank you.

MR. GREENBERG: Steven Greenberg here, on behalf of US Combined Heat and Power Association. We've heard you and Mr. Putnam talk about distributed generation, the proactive approach for solving specific distribution problems or issues.

What about how are you or Mr. Putnam looking at distributed planning from the other perspective, of customers who are putting in say combined heat and power distributed generation because it economically works for them, and taking that into account in your planning process, from the perspective of benefits or costs or where those two curves might intersect?

MR. SEGUIN: My first instinct, and this is just off the top of, we hate CHP because it takes 8,760. That's not exactly true. What we need to do, and we haven't done it, and these are just my thoughts as I go into my thin year of doing it, is that we need to get with the architects as they begin to build new buildings, and to be looking to see for their siting.

And maybe it does make sense for the utility to be looking at CHP, particularly if they own a gas company. So we're not there yet, but it's something we've been thinking about.

There is an association of the architects that meet in our area, and we wanted to -- you know, we call this a road show, and we'll talk to anyone who will listen, and that's part of the communication process. And we're scheduled to talk to our architects in the area.

It'd be nice, in a spot where we're constrained, to consider CHP, and buy our gas at the same time.

MR. RAWSON: Any other questions? Commissioners, if you'll allow it, we'll take just a ten minute break, and then we'll reconvene for the utility panel. And if the utility panel members will come back a couple of minutes earlier and take a seat at the front, Scott will get you started on time. Thank you.

(Off the record.)

MR. TOMASHEVSKY: Our next panel is our utility panel, and what we're going to have them do is react to what we've heard so far. What I found kind of interesting, there was one comment that Rich made that really came, it was kind of a subtle comment that came up in discussion, that had to do really with affiliate transactions.

So, in talking about and making your comments, if you could give that some thought. Because I know that when we dealt with, when we collectively, regulators, dealt with affiliate transaction issues I don't think we were really focusing on the technology side of that.

And that may be one of those unintended consequences of dealing with the financial side of things and how that may impact what you can do with respect to system planning. So I'd like to hear some input on that as well.

And what we're going to do here, we've got three folks ready to speak. On the far side is Scott Lacy, who is a Distribution Engineer, I can proudly say one of my Rule 21 cohorts, representing Edison on the distribution planning side of things.

To his right is Tom Bialek, who started

in that process and actually through that has been able to work at both PG&E and San Diego, so he can give you some perspectives. So, to the extent that John Carruthers wants to defer any questions, Tom may take some liberties and offer his two cents of when he was at PG&E.

John's the principal engineer of distribution planning in the Bay Area Region. And with that, let me turn it over to Tom, because again like I said yesterday, we did not ask for presentations, so he gets additional brownie points for going first.

If you want, you can sit there and I'll just turn this light, and turn it over to Tom Bialek.

MR. BIALEK: Okay, so first of all, Commissioners Geesman and Boyd, what I tried to do in this presentation is focus more on how SDG&E 1 has moved forward and tried to incorporate both DG and DR technologies in its planning processes.

With regards to the two previous presentations, SDG&E as, I'm sure the other utilities here will affirm, that yes they follow traditional processes. But we also do other things, and that's what I really want to talk about in this particular presentation.

What this first slide here, Scott had brought up earlier the requirements with regard to decision 0302-068. I won't repeat it here, but basically it says that utilities will and should look at alternatives to provide lowest cost solutions.

There is also Public Utilities Code Section 353.5. And basically again it says that each electrical corporation, as part of its' distribution planning process, shall consider non-utility owned distributed energy resources as a possible alternative to investments in its distribution system, in order to ensure reliable electric service at the lowest possible cost.

And that's what my presentation is focused on, how SDG&E is moving forward, trying to take this Public Utility Code section, as well as this decision, in some of the things that we're doing.

We have, as both PG&E and SCE have done, have historically used distributed generation as management tools, whether it be for a restoration of customers on a temporary basis or for during the course of emergencies.

What I'm presenting here is really just to give you a flavor, sort of a timeline of how we have been trying to incorporate the broader DER technologies.

And what I've really got here is showing that, I've sort of grouped this into three areas, historic applications, which tend to be group support applications, whether they be rented or leased DG as well as purchased DG, some of the classical applications that we've heard about today, in particular with regards to utility alternatives for distribution planning.

And then lastly what I call creative applications, where SDG&E is moving forward and trying to incorporate other DER technologies into the planning process.

What we're really trying to do is provide an additional set of tools for the distribution planners toolkit.

So, just to summarize, here's some of SDG&E's information with regards to historic kind of applications. We've used rented distributed generation for a number of years. Now, in particular we had a rent/lease arrangement with a DG vendor in the San Diego area for a 1.8 megawatt diesel generator in 1999.

As you can see, we had eight locations where we were using it for system support. In 2000 we had 16 locations where we were using it for emergency support as well as maintenance outages.

In 2001 it dropped to three locations, and that had as much to do with issues with regards to, you know, it was a lease generator, we had some concerns over the lease cost over a period of time and funding those particular projects.

But in 2003 and 2004 we have actually an example where we installed a relatively small application for grid alternative, which lasted basically a year and a month, where it was a remote application, where during some firestorms that ran through San Diego County we lost a number of poles.

And given some of the issues with regards to re-siting the line we chose, as part of our evaluation of our own distribution planning alternatives to look at let's put some generators in there.

Some things to point out about this,

when we actually proposed this to the customers, the single customer at the end of the line, their initial reaction was we don' want this. We don't want this because we don't think it's going to be as reliable as the wires. We want the wires back. And it's going to be too noisy, we have all sorts of people out here on a temporary basis.

So we sat down with them, we worked with them, and demonstrated sound level, sort of along the lines of what DT Energy showed us earlier.

Ultimately we went back in with a steel pole structure to try out some R&D on some steel poles, so that application ended. But for the rented or leased kind of applications during the 2003 firestorms we also used DG for emergency evacuation centers, so that people could gather and get a place to stay.

Now lately we have moved into sort of another phase, where we actually have purchased two 1.8 megawatt diesel generators. They are CARB certified, although we have had lots of difficulties with regards to air quality issues, with regards to CARB versus the San Diego Air Pollution Control District.

But this particular application is going to occur this year. It's a 12 week application, and once that's finished we're going to look for other applications as T&D referrals, as well as use it for substation maintenance.

And in the future we'll continue to explore other alternatives, whether that be natural gas-fired machines or combustion turbines, and as well we currently have proposed 3 megawatts of PV on SDG&E facilities.

Now moving to what I'll sort of call the classical applications. Back in 1999, in the first DGOIR, we developed, with the assistance of some DG community members basically a DG selection criteria.

The criteria basically looks at a lot of things that Richard pointed out earlier, high cost capacity projects, slow growth areas, new loads with uncertainty in size and timing, low load reduction needed -- and that's somewhat counterintuitive, but realistically it's all about big, 10 megawatt, 20 megawatt sized projects tend to be much cheaper when it's done with wires --

and the solution needed quickly, and then lastly unique customer needs that would drive this.

In 2001 we conducted a pilot to incorporate DG in our planning cycle. We looked at three different locations, we provided that these locations had typically 500 KW, a megawatt, three megawatts worth of capacity needs.

We produced operational requirements, meaning we need this much capacity for this period of time for this length of time.

We also produced and provided to -- as you will see -- pre-qualified vendors circuit maps as to where those locations were that we would want the distributed generation at.

We were looking at, in this particular case, third party solutions. We were not looking at the utility actually going out and doing this ourselves, because we, based upon our history, realized that we already know how to do that, we know how to go buy a generator, put it in and install it.

So, as I said, we used pre-qualified vendors. The reason for doing that is we believe that DG, like any other piece of equipment, is available, we have a process in place to make sure that vendors are credit worthy, have a long operating history, etc.

And so we decided at SDG&E that we would go the pre-qualified vendor route. So we did that, and we did that by approaching both the DPCA and the CADER lists of members and asking who was interested in becoming a pre-qualified vendor.

We sent them out questionnaires, we got responses back, we evaluated the vendors, we ended up with approximately six vendors. We currently have on our web page for distributed generation we do have a contact for those vendors who are interested in offering to SDG&E third party solutions. They would again go through the pre-qualifying process.

But based on what we got back from the pre-qualified vendors was offers to either sell, rent or lease generators to SDG&E. The issues with the pilot were really with regards to the contract terms.

Per 302-68 there are some very distinct requirements for use of distributed generation as a planned alternatives and most of the vendors took, basically then wouldn't agree with the terms. And there were some issues ultimately with the cost-effectiveness of the solutions.

SDG&E has now moved forward to

incorporate DG planning as part of our annual capacity project determination. We will approach our pre-qualified vendors with an identified project when we have an identified project, we will utilize our Commission-approved form contract.

And then once we do get responses we'll look at final solutions, evaluation, and selection guidelines.

Lastly, in the course of doing all this we have developed some standards and guidelines for distribution planners to use in evaluating these alternatives.

Another classical application, Richard talked a little bit about the backup program. SDG&E, in 2001, instituted a rolling blackout reduction plan. We got that approved by the CPUC, where we aggregated existing customer diesel backup diesel generators.

Currently it's an existing program, we currently have 60 megawatts signed up. We worked with local and state air resources boards to allow this to happen.

What we do is we dispatch the units, once the ISO declares the stage three emergency.

Again it's diesel. When we approached them earlier to try and avoid going to a stage three the response typically was, you know, we really don't want you to do that.

And then lastly, once the units are running and once we know that they're running, we reduced the blackouts, the load that we have dropped, by the amount of confirmed capacity.

In order to, Richard talked a little bit about if you make it worthwhile for the customers, they will ask you to participate. Well, in order to get our participation level to operate at 35 cents per kilowatt hour capacity payment for the amount of load that they dropped with their generator.

Next is really what I call our creative applications. In our 2002 filing for our cost of service we implemented a sustainable community, a proposed sustainable community program. It was approved in our Phase One decision.

We have an annual budget of $5 million. And part of the sustainable communities, we're looking at things like energy efficiency, demand response, distributed generation, water and other resources, primarily looking at the whole concept of green buildings meeting Title 24, and looking to see what we can learn as far as impacts on our distribution system.

We have currently one TKG project completed, where we've installed 45 KW PV, and we also have a five kilowatt fuel cell which is operational.

We have another project scheduled for moving forward this year, Mar Vista, which is a 75 kilowatt PV rating, a 250 kilowatt fuel cell. This is really more or a residential kind of application, where we're thinking about how we can incorporate the fuel cell to provide power to not only the single end user but to multiple end users.

Continuing, we are moving forward, and have since 2003 looked to incorporate distributed energy resources, the broader concept of distributed energy resources, into our planning process.

Again, looking at spanning the planned alternatives. We're really looking at utilizing all tools in an attempt to impact load and system load growth. We're seeking a minimized capital infrastructure expenditures and also to increase our system efficiency.

We're also developing some applications based upon customer needs. We currently have monthly meetings with our energy efficiency and demand response teams to identify opportunities and we're looking for some opportunities for this next planning cycle.

We have an improved program with Celerity, a demand response program. It's an ISO stage two program. What Celerity has done is they have approached some of our customers in our service territory and are seeking to convert them from diesel to natural gas.

Our contract will be for them to supply us with ten megawatts of demand reduction in 2005, and 10 megawatts in 2006, moving forward for a ten year program.

Another application that we're looking at, circuit savers program. In this program we've identified 20 highly loaded circuits, and what our marketing people are doing, mass markets, major market, looking at targeting energy efficiency, DG and demand response in these areas, and we're monitoring circuit loads to see what impact this has on our circuits.

Next is the zero energy new homes. This is a PIER R&D project and proposal. For SDG&E's portion it's approximately 60 homes. Designing homes to incorporate all sorts of DR technologies, to test these DR technologies and programs to optimize electrical system infrastructure and to produce maximum benefit for our customers.

And as part of this program look to see what are the costs and benefits of the program, how will they impact our infrastructure, and then also future SDG&E facilities.

And so in summary, since 1999 SDG&E has continued to explore alternatives as part of its planning process, and that SDG&E is committed to appropriating DR in the planning process and pursuing alternatives as they evolve.

And that's it. Any questions?

MR. TOMASHEVSKY: Well, we'll hold off on that for a minute. Okay, we're going to move up the state and go over to Scott Lacy.

MR. LACY: When Scott called me, Scott Mark actually called, and asked for me to sit on this a couple of weeks ago, it was mainly focused on trying to provide some additional education on the distribution system planning process, so I kind of had in mind a very similar distribution system planning 101 idea, and that's what I was really ready to present.

And then I saw, you know, Mr. Putnam's presentation on the website a day or two ago, and said well, I'm pretty much done. Because in many ways this covers in very good detail the process that we have to go through, and as a matter of fact I'm thinking about asking if I can borrow it from him to see if I can educate some of our new engineers we're supposed to be hiring this year, on how the process is supposed to work.

So I'm really going to try and focus on some of the specifics for Southern California Edison and some of the statistics more than anything else as far as our system planning, and not cover too much of the process, because he's covered it quite well.

As many of you probably know, our system typically runs on the order, on a summer afternoon, on the order of 20 to 22,000 megawatts of peak demand.

We have approximately 4,500 individual distribution circuits, a little over 800 substations, and in order to manage that some of the questions that came up during Mr. Putnam's presentation, we have approximately 25 or 30 distribution field engineers like myself that manage the planning for that system.

We're broken up into four separate regions, and we are out at these field locations and deal closely with the local planning folks, the local operating folks, to help manage that system both in a long-term planning aspect and also we do get pulled in during the hot summer afternoons and work well into the evenings trying to figure our where we're going to swap load around for the next day to make sure we get through it.

Paying close attention to two and three day weather forecasts to determine and project what the load's going to be on these circuits tomorrow and the next day.

We currently expect or are anticipating approximately two percent growth rate system-wide, which is about 500 megawatts a year. And of course that comes in pockets, as Mr. Brent from Solar said earlier.

We have roughly, what we call our A bank systems, which basically are our main sub-transmission interface systems, 220 KV to say 66 KV. There are 42 of those around. Of those 16 typically have anything higher than a three and a half to four percent growth rate, and they usually absorb most of resources an dour efforts.

And as was indicated yesterday a lot of them are on the east end of the world right now, the San Diego-Riverside area, out in the San Bernardino pass, and then the other very high growth area is down in Temecula, Murieta, that area.

As we look at these projects, you know, obviously some have, we might want to say, a two percent system average. We have areas that are four and five percent and growing very quickly, and some that are in some cases almost growing in a negative growth in some aspects, because people are moving out to the east end.

To compensate for that 500 megawatts we typically install approximately 50 or so new circuits each year. We use those for a variety of purposes, it's not just -- as Richard was talking earlier -- we talked about one megawatt problems, and usually what we do, in the overall process is we try to stretch the system as far as we can within reason of course and the criteria.

Which means that we will take advantage of as many opportunities and alternatives, such as transferring loads to adjacent substations, trying to balance out our circuits as much as possible, and utilize nearby circuits that may be under-utilized and transfer loads to them.

And when we have area-wide problems that's usually when we end up having to result to some of the larger ticket items like new circuits, substation additions, and worst case obviously, brand new substations, which of course are the big dollar items, because we then are talking about new property acquisition, we're talking about rights of way for sub-transmission lines coming in.

Again, that is in the five and ten year horizon because the big issue we have of course with that is rights of way, and GO 131D is a huge impact to us when we're planning new facilities.

And so we try to minimize our use of that and maximize our existing properties until they're just bulging at the seams with transformers and circuit breakers and everything else and we just can't go anywhere else.

Our criteria basically ends up being, you know, we typically standardize on 12 and 16,000 volt circuits are the predominant for our distribution circuits. We do have a fairly good number of 4160 circuits, but on the 12 and 16 level -- and you'll see this in Tom's presentation this afternoon as well -- we try to focus on roughly 400 amp circuits, with the emergency capacity of about 600 amps.

And we'll also have multiple ties between circuits, which is why we like to keep it at 400 amps, so if something goes wrong we can move multiple chunks of those circuits to adjacent circuits and not overload them as well.

The overall process for distribution system planning is, as Mr. Putnam indicated before, yes it is year-round. We're very attuned to predominately the business section of the newspaper in the local areas to see where some of the new loads are coming in, looking at housing startups.

We have contracts with folks that deal with permits issued. We're very attuned to looking at, you know, individual city and county zoning plans and general plan updates to see where the loads going to be going, so it is a year-round program.

In earnest, we normally run it between October and April, is about our time period. Normally October is about as early as we can start. The last few years our system peak has been anywhere from mid to late September.

The main reason for that, not only for the weather, is the fact that you have most of the school systems that come back in. A lot of the schools have been doing a lot of work to add central air conditioning that they have not had previously. I know I didn't have air conditioning at my school when I went there.

And they do now, so, they're getting off easy now. So we see a lot more load come up in September actually than we used to. Ten, twelve years ago most of our peaks used to be early August, so the commercial load was predominate.

The other issue that we see often, and this gets in to some of the discussion yesterday and some other aspects, is that our peaks normally at the distribution level are happening between, typically between five and seven P.M. in the September time period, and that is mainly due to residential air conditioning loading.

People do a really good job of keeping their air conditioner set really low when they're at work, and when they get home they want it to be nice and cool like it was in the office they just left.

So we se huge spikes come up in the evening hours. So that's a big aspect that we have to play around with.

So, again, we start in October reviewing our peak loads that we just saw over the last month or two or three, depending on when the heat storm came through, or multiple heat storms came through. We go through and do the temperature normalization, as Mr. Putnam indicated.

We have established over time some what we call temperature sensitivities for each individual substation.

Obviously if you have a substation that is more focused on serving residential load the temperature sensitivity is going to be higher, because of the air conditioning load, whereas an industrial focus substation the temperature sensitivity is going to be less than one percent per degree because, you know, they're going to be running their plant whether it's hot or cold.

So we have to adjust for that at a individual substation level. We then go through and determine, between the load forecasting which again is a year-round issue and talking with our local planners, talking with local business leaders, develop what our forecast is going to be for the subsequent years, and then compare that to our criteria.

What is our available capacity on those substations, what is our standard criteria for our circuit loading and flexibility for liability in operation, and develop the alternatives, the cost-effective alternatives, and yes there will normally be anywhere from two to three to five different alternatives for each criteria violation that we see.

We'll go through and price out several different options, select the most cost-effective one, which will give us the best bang for the buck over a multiple of years, not just looking at what will fix it for next year but what will be a long-term fix for the next several years.

And develop that end of the plan, take -- and then of course as we do a capacity increase at one substation, now all the neighboring substations are going to transfer their loads to that one -- again, we're fixing area problems, not just individual substation problems.

And readjust our forecast, so that now we also can roll up that forecast into our next higher level, going from our distribution subs now into the sub-transmission substations that I referenced earlier, do a similar process for that. And including the sub-transmission lines that go to those substations.

So, throughout that process, as I said, that normally goes through October to April, develop the costs, run that through our management system, and get final approval within that, obviously managing budget and everything else.

And then recognizing the construction issues that we have, not only funding issues but construction issues, we have already, you know, our plan for the next ten years. Yeah, we do a ten year plan and we do it every ten years.

Our plan for the next ten years was approved just a few weeks ago by our technical review council, and we have already issued to our planning group the scope of where those circuits need to go for the 2006 time frame. So we currently are in an 18 month window to develop our scopes for construction, for operation, for June of '06, because June of '05, you know, our scopes were developed a year and a half ago.

One last thing I'll talk about. As I said, we are distributed in the four areas. We did have to develop an internal software and database system where we manage all of our substation capacities, compare that to all the loads.

We have some mechanism where we can receive the information off of our status system. Our substations, in general, we have about 60 to 70 percent of our substations are automated, so we can receive that data automatically.

Those that aren't, there was a small reference to Mr. Putnam's presentation about circle charts. If you guys have never seen a circle chart, they are A, you've got to wait for the substation operators to go out and collect them and then mail them to you; and B, then you get a stack like this of circle charts that you then have to interpret and determine what the load was on that substation at the right time.

So in those locations, gain, that's why it takes us awhile to get all the right data and proceed, but we do then input that into the centralized database. Luckily, you're right, the mainframe is gone, but we have server systems now so we can concentrate everything on the server, access it remotely, everybody's using the same criteria and it's locked in there.

So we have some checks and balances against that. So, I think I've rambled on about the system long enough, so I'll probably rely on your questions later, so --. And then, again, Tom will have some issues related similarly to San Diego's efforts on implementing DG into the planning process, Tom is really going to focus on that this afternoon.

COMMISSIONER GEESMAN: Can I jump in and ask a couple of questions while it's still fresh on my mind? And thank you for a very informative summary.

Who actually does the load forecast?

MR. LACY: The load forecasts are done predominately by, ultimately the responsibility is to the individual distribution field that owns that area. And of course there are a lot of checks and balances that goes on, not only do we have our own internal management that ensures that it makes sense, it, you know, passes the smell test, and of course we have a lot of other tools that are made available to the engineers -- housing starts and some of that other data that we get from SCAG and some others, so --.

COMMISSIONER GEESMAN: But does each planner then develop a forecast using the same assumption and methodology, or do you have a specialized group that works up the forecast?

MR. LACY: We try to coordinate, you know, we have a separate group within the company that does I'll say system-wide forecasting, that deals more with the ISO.

COMMISSIONER GEESMAN: I understand that.

MR. LACY: And we do a lot of cross checks with that. And when we go from the bottom up it is going to be a little bit different from the top down than they do --

COMMISSIONER GEESMAN: Sure.

MR. LACY: -- and so we'll have checks on that as well. We do not have a dedicated group just for forecasting, the individual area engineers are responsible for their own.

COMMISSIONER GEESMAN: And you suggested that you're broken down into four areas?

MR. LACY: Yes. And that matches up with our operating regions, so we just match with them.

COMMISSIONER GEESMAN: And do you have in-house proprietary software or do you rely on a commercial vendor to supply software for your work?

MR. LACY: No, we developed it in-house. It's predominately, you know, it's predominately just a database system that was developed, it's a database application that runs on a common web server.

COMMISSIONER GEESMAN: And you're looking at, if I remember Mr. Putnam, an 18 month, a five year, and a 10 year horizon. Is that what you utilize?

MR. LACY: Yeah. We normally talk about a ten year plan. We do eventually sum up. Obviously we do focus more on, in certain presentations we'll focus on the five year.

We have the ten year again because of the long-range needs for our transmission group which deals with the ISO controlled areas, which is actually separate from our group, and then -- which is the bulk power stuff -- and then also because we know that, especially when we're dealing with brand new substations, and A banks in particular, that the property acquisition, the permitting, and those efforts are now typically longer than five years.

So we need to identify them as early as possible, at least have a placeholder for them.

COMMISSIONER GEESMAN: And how high vertically do you try to roll up these four graduated forecasts? Are your transmission forecasts basically aggregations of your distribution system forecast, or is that separately done?

MR. LACY: Yes, for the most part that group will take our input, as far as our distribution level forecast. They'll cross check it with their own assumptions and also checking with the system forecaster, and run their own.

COMMISSIONER GEESMAN: The system forecaster, though, uses a different methodology -- I understand that the parts don't necessarily sum to the whole?

MR. LACY: Right. Because you get into coincidence factors, you get into diversity, you get into some other issues.

COMMISSIONER GEESMAN: Thanks a lot.

MR. TOMASHEVSKY: Thank you, Scott. John?

MR. Carruthers: For the sake of -- I won't get any brownie points for not having a presentation, but maybe I can get some brownie points by keeping my comments short because I'll just end up repeating what Mr. Putnam and my comrades from San Diego Gas and Electric and Southern California Edison have already gone through.

But basically much of Mr. Putnam's presentation regarding distribution planning 101 marries over to PG&E's process quite well. I can probably, jus like Scott here, take it and mark it up for the nuances that apply to PG&E and take it out to our distribution planning engineers, new planning engineers that is. It's a training tool almost.

So it does provide a very good overview of planning 101, as apparently SCE conducts it as well, and probably San Diego too.

What I do want to talk about a little bit more is on the DG side and how PG&E looks at DG in evaluating capacity projects, how we incorporate that into our planning process.

In 1998 PG&E developed a distributed mobile generation guideline. And what that did, the various criteria for our distribution planning engineers throughout the system to use as a screening process when they were evaluating alternatives for distribution planning, or distribution capacity upgrades.

So for example, as Mr. Putnam described, we forecast the load, we identify the deficiencies, we identify the traditional wire solutions to those deficiencies. We do some rough cost calculations to get an idea of what the economics of that are.

And then through this guideline that we developed the planners could compare the cost of the traditional wires upgrade against the cost of using a mobile distributed generator, much like Richard from DTE was talking about previously.

And to date, we've found some cases where it's close in terms of the economics associated with using mobile distributed generation as compared to traditional wire applications, but we haven't had to use that.

The other aspect that I want to point out from a PG&E perspective, relative to the capacity process, is we're fortunate from a budgeting and prioritization process, the capacity projects on the distribution side receive a very high priority.

We have a pretty good process, much like Edison's relative to the time frame. Our peaks might be a little bit sooner than theirs ,so we might have a little bit of benefit in terms of time for looking at alternatives and executing the detailed estimating and construction plans associated with those.

But we're successful the vast majority of times in implementing capacity upgrades by the time we need them, which is typically around the May 1-June 1 time frame.

We don't always hit 'em on time, and there's risks associated with that, as Mr. Putnam indicated. But for the most part we have been pretty successful and we have a pretty robust capacity planning program.

In cases where we have particular

distribution planning areas, in the PG&E distribution planning areas there are about 220 of them or so across our whole system. There's a collection of substations that we use for gathering historical load data and for our load forecasting process.

It breaks it up, like Mr. Putnam indicated, into a more manageable, analytical tool.

And we'll be getting a case where we have a significant deficiency on a distribution planning area basis, we sometimes look at and have special studies conducted relative to what DER DG resources might be able to do for us in that area.

The most recent example I can think of was in 2003 in our delta 21 KV distribution planning arena. We were faced with some deficiencies, we retained E3 to look at the potential uses of DER and DG applications within that distribution planning area.

They did a pretty comprehensive study and for that particular planning area they concluded that it was just better to proceed with traditional wire solutions to those deficiencies.

But that doesn't say that in the future

there can't be some sort of correlation or some sort of confluence of events where we meet the right amount of dollars, the right need, the right timing, where things can come together and other DER or DG type applications might be suitable.

Of course we'll be watching Edison's RFP relative to integrating DG into their planning process. It's my understanding that they're going to be talking about that this afternoon.

I've chatted with some people involved with that process. PG&E's kind of monitoring it. We want to see what kind of response Edison gets back, and see if they get good bona fide responses back that really work relative to their distribution deficiencies PG&E would be open to a similar process for PG&E's system.

So basically, in summary, distribution planning process is very similar to the other utilities in California. We've been looking at DG mobile distributed generation as part of our planning process since 1998, and we're keeping a close eye on some of these other things that are going on with SCE and we also do our own studies or hire consultants to do studies to help us out in evaluating DER and DG applications for particular distribution planning area deficiencies.

COMMISSIONER GEESMAN: I had a question actually for each of the three of you. If you'll remember Mr. Putnam's color chart on the investment thresholds, he indicated a different threshold for feeders compared to substation investments.

Does that capture the difference that each of your companies recognizes as well?

MR. CARRUTHERS: Go from my end, or start with Scott?

MR. LACY: Sure, in the general sense I would say yes. Clearly for all the same reasons he provided we would focus on a substation overload project much more importantly than an individual circuit project, because of the customer load at risk.

You know, the potential for outages, the negative impact on customers. So, certainly we'd look at that. Normally we don't have, there's kind of a format but we don't really have that kind of criteria, but when ranking projects against each other yes, certainly a substation project.

And actually, you know, there are certain times, I suppose, where you'd say well, a substation project with a five percent overload may actually be running a little lower than a feeder only project with a ten percent overload, because of the probability. And there's many factors that go into that.

COMMISSIONER GEESMAN: What about the others?

MR. BIALEK: SDG&E, same criteria, maybe a little bit different applications. We will look at things like the amount of overload, the rate that it's increasing as a function of time, where it is, what other options are available to us.

COMMISSIONER GEESMAN: PG&E?

MR. CARRUTHERS: Yes, it's similar from a substation side, just because of the amount of load and number of customers that can be affected from a substation transformer outage is many thousands of customers in a typical suburban substation.

PG&E, probably like San Diego and Souther California Edison, variety of different transmission voltage levels and distribution voltage levels. For PG&E, 4 KV, 12 KV, and 21 KV are typical, but over time we have purchased a fleet of mobile transformers at various capacities, transmission voltages and distribution voltages to be able to take care of those cases where we have a distribution substation transformer failure.

In terms of the relative ranking, yeah, we might generally look at those substation issues first, or rank them somewhat higher. But a lot of that is a judgment factor, and a lot of that judgment factor revolves around how big the deficiency is, where the deficiency is particularly at, what the fix to that particular deficiency is, and those kind of things.

For example, if it's 1,000 foot of conductor with a low percentage overload that might get pushed down, because if we did have a failure we could replace that relatively quickly anyway.

There's also things we've done in terms of altering our capability of various facilities. We individually customize transformer ratings based on their actual operating history and condition, their ambient temperature operating. We customize virtually all of them at this point now.

COMMISSIONER GEESMAN: Every transformer in the system?

MR. CARRUTHERS: Well, I don't know that every single one --

COMMISSIONER GEESMAN: Almost every one?

MR. CARRUTHERS: Any one where we're going to start looking at a distribution capacity upgrade we would have our substation asset management group look at that particular transformer and say okay, what, looking at the construction of the transformer, the manufacturer of the transformer, how long it's been in service, various oil tests, ambient temperature, it's temperature from the winding and the oil, and looking at all this kind of data, the number of faults it's seen, all this kind of thing.

They have a model they kind of crank out and go "you know, our normal criteria for a substation transformer might be this, but for this transformer you can get more." Sometimes you get surprised, and they come back and go "no, you can't actually get what we might have expected out of it."

Then we really, then sometimes we get

caught short a little bit. But that's more the exception rather than the rule.

COMMISSIONER GEESMAN: I see you other guys kind of nodding your heads. Do you try and customize your analysis to the transformer in that situation?

MR. LACY: Yeah. We have individual ratings for each transformer. We don't necessarily rely purely on the original manufacturer's name plate.

MR. BIALEK: It used to be like a name plate and a percentage.

MR. LACY: Right. We do individual heat runs for each location, based on load factors and duty cycles and the like.

MR. BIALEK: Yeah, we're doing similar kinds of things at San Diego. Maybe not to the extent that some gas electrics have, but --.

COMMISSIONER GEESMAN: Thanks an awful lot.

MR. TOMASHEVSKY: Any other questions at the dais?

And just as a program note, we are going to go on to the next section after this, before our lunch break.

MR. BRENT: I'll try and make it quick, thank you. Richard Brent, SDG&E. Would you be kind enough to put up the second slide? I was fascinated by the PUC siting. Yes.

Scott, I didn't hear much description on how SCE looks at that PUC siting, and in particular if you could address the value of non-utility owned distributed generation resources as a possible alternative when you just finished off talking about the challenges with transformers when you're upgrading. So, if you wouldn't mind?

MR. LACY: Well, yeah, what's the best way to describe this. What we ended up doing is, through the course of the process we developed our list of proposed alternatives, you know, our traditional approach.

And go through those in a similar fashion with what Richard ended up at the bottom as far as looking at candidate locations where we may have a short-term deficiency -- and again, Tom's going to get into some of this in the afternoon, as far as the process that we've continued on how we're going to contract with potential candidates.

And using an analysis tool to come up

with where these possible candidates are. So it kind of does come after the fact as one of the possible alternatives in lieu of one of our otherwise selected traditional alternatives.

MR. BRENT: Well, you made a good point about Tom this afternoon, I'll be patient. Thank you.

I did have a question from the SDG&E gentleman. I looked at your discussion about the distributed response program, the demand response program using natural gas engines. And I'm hearing from other places in the country that demand response may be no more than say 200 hours a year.

I'm curious as to why you might find that people have to go to natural gas when it may be within the limits of the units that are on base as liquid fired?

MR. BIALEK: Well, again, this particular program is not a SCE program that we're actually designing, it was a program that we were approached by a third party, Celerity, and this is their approach, given some of the issues with regards to diesel.

MR. BRENT: So, independently, from your

model, they're making the choice to go to natural gas?

MR. BIALEK: Correct.

MR. BRENT: Thank you. Do you know how many hours of operation you expect in that kind of demand response natural gas fired machines?

MR. BIALEK: I would expect that, if you look at some of our tariffs, we're something on the order of certainly no more than probably 100 hours.

MR. BRENT: Last question, if I may. You talked about the zero energy program. Is that a land field brown field development or is that more green field?

MR. BIALEK: No, that would be a green field.

MR. BRENT: Okay, very good. Thank you very much gentlemen.

MR. TOMASHEVSKY: Any other questions?

MR. EYER: A couple of general questions, Jim Eyer, Distributed Utility Associates. Expense budgets and capital budgets are treated very differently as we know. Expenses are pass-throughs.

To what extent does a limited expense

budget limit or constrain the use of distributed resources? That is to say if a million dollar capital solution was on the table and a $500,000 rent was the least cost, at least from the ratepayers standpoint, is that a constraint?

And then secondly, this might be a can of worms, but how do we decide the level of pain, if you will, with regard to customer outages? Is there a metric, is there some sort of methodology or criteria used for that? I'd be real interested in those two points.

MR. CARRUTHERS: At PG&E we use, we obviously analyze the proposed solutions to particular distribution capacity deficiency issue economically, and our tool -- we call it Esapa, economic analysis software program -- and it has provisions for entering in capital expenditures and expense expenditures in streams.

And for those instances, just like you said, where we might be relying on distributed generator, whether we lease it or, you know, typically that's kind of how we think about it.

We would, that would be entered in as an expense stream, and that would be compared to the analysis of the capital dollar stream associated with the traditional wire solutions.

At the end of that it produces a revenue requirement associated with all the various choices, and all the other things being equal from an operational perspective we'll choose the solution that yields the lowest revenue requirement.

MR. EYER: So you would have no trouble getting additional expenses above the normal maintenance O&M that you'd have to apply to your equipment, your existing infrastructure? That was really the stream I was getting at.

MR. CARRUTHERS: Yeah, I hear you, and I think it hasn't come to that point where we found that application yet. But I'd like to think when we found that application that, you know, if it's the right thing to do relative to revenue requirement and ratepayers, that we would implement that kind of solution.l

That's what we're trying to do, that's why we do all the economic analysis for the programs, otherwise we would just overbill capacity projects for all sorts of different reasons from reliability, you could buy reliability with capacity.

MR. EYER: Say no more.

MR. CARRUTHERS: Yeah, so it's the right thing to do. In terms of the paying part, we don't think of capacity projects in that light. We don't think of it in terms of is there a ceratin criteria where we'll allow a certain number of outages to occur because we allowed an overload in equipment failure. It's just not part of our process generally.

MR. EYER: Except in the really gross sense, where you prioritize substations, because clear there's going to be --

MR. CARRUTHERS: Oh, yeah, I mean, that's a risk management thing of course, but there's no specific criteria per se, no.

MR. BIALEK: At San Diego I would say that, pretty similar to PG&E. Effectively what we're really looking at is what is the lowest cost solution. So now we're sitting there comparing that, doing that analysis of the potential wire solution versus a distributed generation solution or a DR solution.

And we would then, assuming we get the equipment installed and have the appropriate securities of performance, then we proceed with the lowest cost solution, that's sort of the bottom line.

And as far as prioritizing by any particular customer impact kind of thing, it's somewhat inherent -- as John pointed out -- in the process is you've got substations with lots of customers on in, and, to give you another perspective.

If a substation goes out with a lot of customers there's a lot of publicity, there's a lot of negative PR, and there's a lot of regulatory after-the-fact of why did you do this? So it tends to push you somewhat in that direction.

MR. EYER: And it is an art, rather than a science, trying to pinpoint that threshold, if you will?

MR. BIALEK: Yeah, it's, at this point in time, I mean, nobody's got any really hard and fast rules as far as, you know, here's where you go now. It's just someplace over 50 percent overload. Maybe some day.

MR. EYER: Great.

MR. LACY: So, yeah, like i said earlier, we're always looking hard at the inverse of the capital expense, and we will do the full-on analysis on which one makes more sense at the time. So we'll look at each one and make hopefully the right decision at the end.

And again, as far as the interruption factors, yeah it is more of an art to say that, it's common sense more than anything else that you're going to tend to want to do the substation projects in light of the likelihood of customer interruptions than you would on a circuit-only project.

MR. TOMASHEVSKY: Thank you, gentlemen, appreciate your time.

MR. RAWSON: As Scott mentioned, we're going to shift gears a little bit. And now that we've had kind of an introduction as to how traditional planning is done an dhow some utilities are looking at it a little more progressively at implementing or integrating DG into their planning process, we wanted to talk a little bit about the research that we've been doing in the PIER program here at the Energy Commission.

It's trying to do two things, develop new tools for planners to use to better understand their system and understand how distributed generation and demand response can be beneficial to their system.

And then later we're going to talk about some work that we've been collaborating with Edison on, on their deferment program.

But first up let's have a talk by Peter Evans from New Power Technologies. He's going to talk about a project that we just completed Phase One on and initiated a new phase on.

MR. EVANS: Okay. The development objectives has turned into a multi-phased project. And I think that the original motivating factor here was the desire on the Energy Commission's part to find systematic ways to fully incorporate DER and delivery system planning.

Actually, this is a pretty good education for me this morning, hearing how people are actually doing this already, so hopefully this advances the thinking somewhat.

Specifically, for this project, systematic methodology to determine the location, size, and characteristics of DER projects that will enhance power, delivery, network performance.

To quantify the benefits of those

projects, and to assess the merits of wires and non-wire network upgrades on an apples to apples basis.

From a network operator perspective this approach would yield some answers to some of these types of questions, and actually this is the way I'm going to talk about this.

How does network performance work at the distribution level? How is it really, what is going on, and how is it affected by or does it affect the overall network. This is really the vertical look that Paul Bach was talking about yesterday, looking at distribution, looking at transmission, and the interplay between them.

Second, how might the re-dispatch of existing resources improve network performance? What's he potential of demand response and DG, especially in the distribution system to provide benefits as measures for network performance and how might they compare to traditional wires upgrades.

And what are the location and operating characteristics of D and DG required to achieve these benefits? Another way of asking this last question is can I identify a project that helps me, or identify projects that hurt me?

Either ones that I might develop as a system planner, or noes that I might respond to that come in by a customer or some other third party.

One thing I want to say about this, our point of departure with this really wasn't looking at DER as a way to remedy overload situations, and actually the system that we looked at, the one I'll give examples for, there were no overload situations or pending overload situations.

So this isn't really a, we didn't approach this as a problem of how to defer or replace network upgrades. It could be applied that way, but what I'm going to talk about really is looking at network performance sort of on an ongoing basis rather than correcting or avoiding situations that might cause customer outages.

So, you know, I guess that's a departure from the type of perspective we've heard through most of the presentations this morning, and it's a little different point of departure. I guess you'll have to judge for yourself what really that means.

Our approach was, first of all, to

consider transmission and distribution as a single integrated power delivery network. And again, this is the vertical look that Paul talked about yesterday, trying to capture them all within a single analytical space.

And that's a departure from, I think Judd's presentation this morning I think the last point of his last slide was these circuits are considered independently. In our approach they're all part of one happy network, both transmission and distribution.

Secondly, the demand response distributed generation and capacitors are all available interchangeably as DER options. And then we concocted a variety of measures to capture overall network performance.

So it's not just is there an overload situation that i'm avoiding. Really it's having to do with network performance on an ongoing basis.

We made an assumption that the individual DER devices could be individually dispatched and coordinated for network benefits. For those of you that are in this business you know that that's a pretty brave assumption, and the main reason we made it is I was curious to see what impact it would have.

I actually believe that this type of individual control will pretty soon become the normal state of things, but as things stand today I understand that not every one of these devices presently -- not every switch, not every capacitor, not every generator, not every demand response device that's in the system is individually dispatchable.

We used a product developed by Optimal Technologies called Aim Fast, which is an analytical engine, to go through and determine individual network locations benefitting from resource additions.

This is something that can be done by hand, but when you're talking about an integrated network with potentially hundreds or thousands of potential sites where resources could be added, it helps to have, and you'll see it actually helps a lot, to have an analytical tool that can assess the overall network and run a series of calculations to determine which specific locations bus by bus block by block would benefit the most from resource additions.

And then we characterized the potential benefit from DER as being the benefit that we observed from a set of hypothetical projects for optimal DER portfolio.

This isn't to say that this is a portfolio of projects that you might go build, but it's one way to measure what really the maximum potential benefit from these distributed resources is. And maybe you could go build this resource portfolio, it depends on what they are, but this is really an attempt to assess what the maximum benefit could be.

As Mark indicated, we're in the midst of this development process, but I think at this point we can conclude that analysis of this vertically integrated system with distribution and transmission together yields insights that are otherwise unavailable.l

That demand response local generation and capacitors can in fact provide significant network benefits, if they're in the right location and the right size and their operation is coordinated.

Now, another point I want to make here that actually was in my presentation is that we found that these benefits are not limited to summer peak conditions, and so what you're going to see is that, it's one thing when you're planning for potential outages and trying to mitigate for potential outages, but if the objective is to maximize network performance the benefits are year-round.

And so perhaps it's a departure to think of DER as sort of a steady state device that's in the system that's used seasonally in different ways, but it's not just something there for those top one percent hours of the year.

We did find in this instance that DER projects could yield a comparable benefits relative to conventional network upgrades. That actually wasn't really one of the intents of this project at this stage when we went into it, but it happened that the utility had some network upgrades that they, they actually implemented them, and we were able to look at the network with and without, and with and without these DER solutions and compare the effects.

So there is the potential, there's a realistic set of tools, DER can be used to yield the type of network benefits that you might otherwise get from traditional solutions.

And then the last one, of course, the actual results will vary. Until you run the analysis you can't figure out, or you don't know, whether DER really has that potential for a given system.

This is, I think this is old news for most of the people here, what a departure it is to integrate distribution into a transmission system. I think somebody said earlier that there's about five times as many pieces in a distribution system as there is in a transmission system.

I guess we found that, with this particular local transmission system, this was a city-based utility, about 500 megawatts of load, and it's within the PG&E system but it's a municipally owned utility, this particular example.

And within regional planning this system is characterized with two busses, two 115 KV busses. And then the loads are sort of hung off those busses and the generators are mounted off those busses, but it's two points.

The utility itself models it's system using an 80 buss transmission model, and we modeled the system at about 850 busses. So there's, you know, a couple of orders of magnitude growth in the amount of stuff that's in the model from what we started with the regional transmission model and how we modeled it.

Our characterization in the system was an 850 buss system. We modeled 48 of the roughly 100 primary distribution circuits. In hindsight we probably should have done them all, and if I would do this again I would do them all.

We modeled all the customer load sites individually, there was 422 of them. There were six existing embedded generation units, which we modeled as independent sources of real and reactive power.

We also modeled all of the capacitors individually. And then that model was fully integrated into the 13,000 buss WECC transmission system.

I should mention that in the utilities model, you model generators as negative load, and they actually modeled capacitors as negative reactive load, so they weren't in there discretely.

And then another thing I should mention, because it came to mind in some of the discussion earlier, is that this particular system is highly networked. There's about 100 links, 106 links between the 48 circuits that we modeled.

I think that's more than most. We modeled them as radial circuits, but we actually did some analysis looking at how might this be different if they were networked, and that's going to be one of the things that we looked at in more detail in the next phase.

I think this is the first time that this type of model has been created, that fully integrates transmission and distribution with all the individual distribution elements modeled in a single power flow model.

So this is the model that we found, and again this is looking just at the transmission system, this is the way that the utility would look at it. You'll see a bunch of these graphs and they're all similar, and that is -- this is voltage on a per unit basis, so it's looking across the system, in this case 60 and 115 KV voltages are all characterized as 1.0 per unit.

And it'd be nice to have the voltage in the system range between 1.05 per unit or five percent over and five percent under. And in this particular case we can see that all these points are, so this is not a system that has any overloads, there's not customers that are going to see outages.

It's a summer peak condition, these data are actually taken from the highest hour in 2002 for this system. Everything is within plus or minus five percent of rated, and so it's actually a pretty well behaved system, not one that an engineer would look at and say gee, this needs to be fixed.

But the thing to notice about this, this is just transmission. So anything we do at the distribution level is invisible with this way of looking at the system.

So our focus is going to be on the center loop, the core, and the north loop. This south loop down here is mostly residential, so I'm going to move these over. This is the same data.

And then when we add in the distribution data this is what it looks like. And what you can see here, first of all there's a lot more detail, by an order of magnitude more points on the system.

But there's also more voltage variability and more low voltage parts of the system, once we add the distribution system in.

And then really the key point here is that any changes we make at the distribution level will become immediately visible if we re-plot this graph.

And this is a look at the system looking at the blue, which I indicated was the highest hour of peak, and then the red, which I call the need peak, and that's sort of a normal summer day but not the highest one percent.

And then the yellow is winter peak conditions and the blue is minimum load conditions.

This is all taken from actually SCADA records from 2002 for this system, and what's interesting about this, this is of course what you'd design to is this summer peak, this is sort of an outlier case.

And the system actually has some lower voltage issues during these other cases, and most of the time it looks like it's actually running at pretty high voltages at some of these other locations.

So we found it very interesting to look at the system, choosing a variety of different conditions, seasonable conditions and time of day conditions. And this is just four, so we didn't look at 8,760 cases.

So then in terms of what are we going to do with this, we established an objective where we considered improving network performance. And again, we're not trying to remedy potential outage or overload situations, because there weren't any.

So what we said was we want to minimize real power losses, minimize reactive power consumption, minimize voltage variability, and achieve a target voltage of 1.05 per unit.

And the first step in that, and we'll go through a couple of these, we'll look at existing controls and how re-dispatching existing controls and existing resources can achieve this objective.

We'll also look at reactive capacity additions, demand respond additions, and distributed generation additions.

I also wanted to mention something more about how we did this. I mentioned we use Aim Fast, which is a product of Optimal Technologies, and I see Rich here wants to get the commercial.

The way Aim Fast works, and you'll see immediately why this was so important to this project, what Aim Fast does is it will look at a system and then run an optimization and determine locations on the system where adding resources will contribute the most towards achieving the objective that I just stated on the overall system.

So, for example, this is a look, it quantifies something called the P Index and the Q Index, and this happens to be the P Index. This is just a measure of what the value to the entire system's performance would be of adding real or active power into any one of these locations.l

So, for example we see here, there's a lot of value here, more value in some of these other areas, and then here, this is a negative P Index, that's actually a location where there's too much real power and taking some away would have benefit.

And this is a characteristic result of Aim Fast, and in this particular case this is expressed for the highest one percent peak summer hour. And this is the fundamental tool that we used to do this.

And with this type of analysis you can actually go through and rank each of these locations from best to worst, in terms of the value of adding resources at that spot.

This is the thing that allows us to sort through hundreds in this case potential locations for adding resources and determining which ones are the best and worst locations.

As i said, we looked first at redistributing existing resources, and this is again the voltage profile that I just showed you. We ran an analysis using Aim Fast to determine how these could be re-dispatched if they were optimized, and this is what the voltage profile looks like.

As you can see, it's a very significant impact, at least for this particular system. And the thing that perhaps was a little surprising to me about this was that the localized changes, in this case the handful of changes in different parts of the system, had network wide impacts in terms of voltage profile.

And I'll say a little bit more about what specifically we did.

The next thing we looked at, which were active capacity additions, and then active capacity additions in terms of demand response and distributed generation.

I would say, and it's probably no surprise, seeing the prior slide, that in this particular case there was no additional reactive capacity that had value for this particular system.

But we would run an analysis like the ones that I'll talk about in a second, to look at reactive capacity locations if we found the system to be efficient.

So then we looked at demand response, and we looked at distributed generation, and with optimized additions of demand response and distributed generation this is what the voltage profile looked like.

So you can see, it's very flat, and then I'll explain in some detail what these changes really were.

But the thing I ought to really emphasize about this, this approach is really about individual projects. So, I've talked about these things in generalities, groups of projects, and overall impacts, but what this methodology is really intended to do is identify individual projects and individual locations.

For those of you who have read the report or have seen it, it's very long and part of the reason it's long is because we have pages and pages and pages listing projects at all these hundreds of busses.

So this will maybe give you some sense of, these are the lifting of the feeders -- well, what I did was I sorted the top 100 projects in terms of their ranks, and these are DG projects for the summer peak '02 case, which is the top one percent peak.

I just sorted them in terms of what feeder they were on, and then figured out the average rank of each feeder. I think this is a good indicator of the locations in the system where adding resources had value. And you'll see that some of these feeders that are up here in the top of the list were also the ones that had some of the highest initial P and Q Index.

But the individual locations, looking at averages even distorts the results some. What this is is one of those feeders, this happens to be Core 1, feeder 305, which was the highest on the previous list -- well, it wasn't the highest, it was this one here.

And the substation is here, and the main circuit breaker is here, and then this is just the individual locations on this feeder strung out from the closest to the substation out to the end of the feeder on this regular feeder.

And then the red numbers, maybe you can see them, those are the rankings of in this case demand response projects that were, the ranking found by Aim Fast for these projects.

And what you see is that, well, maybe before i talk about those -- the points here, this is the initial P Index for each of these points. And so as you can see the P Index is highest out at the end of the feeder.

And then the rankings of the projects that we identified on the points, at each of these busses, are shown here in rd, almost n sequence, one two three all the way up here. And then this one down here is ranked 202, so this is a low ranked project.

And my point here is simply to point out that what this does is it shows the system designer, in a lot of detail, where the specific locations on the feeder are where adding capacity has value.

And it may vary in adjacent projects or projects on the same street, you know, in this one feeder we have some projects that are very highly ranked, some of the highest in the system, and then one that's sufficiently low ranked that it maybe isn't really all that important, on the same feeder.

And one other thing is, again probably not a surprise to people that are in this business, is that the highest ranked locations were the ones that were electrically most distant from the substations. So what that means is, adding resources at the substation had less network benefit than adding resources out where the loads were more electrically distant.

In this particular case we asked ourselves why was it that this feeder seemed to receive so much attention from the analytics, and probably the answer is this last buss is a primary distribution customer of pretty good size, and it's electrically the furthest away, and that's a little bit unusual for this system.

These are all customer busses way out here at the end. These busses here are all things like switches, so they don't carry load.

This will give you some idea, again, of the individual character of these projects. This is the demand response projects that we identified on this feeder, and we assumed different levels of demand response for different sizes of customers for different times of the year, and then we used the analytics to rank these and identify which ones were most valuable, or preferred for higher levels of demand response.

So, for example, we assumed that these projects that happened on this feeder, these customers are all medium and large customers, that is over 200 KVA, and we actually assumed that demand response wasn't available for projects under 200 KVA.

So all of these locations were identified as preferred locations for the highest level of demand response under the summer peak, the highest one percent hour of summer peak condition.

Only two of these locations, this one and this one, were identified as higher levels of demand response during the repeat, so there's a sufficient difference in the characters of load between the highest hour summer peak and the regular hour summer peak day that you would actually dispatch demand response differently from maximizing network benefits.

And then under winter peak and minimum load conditions it happened that this feeder, none of the locations were preferred for the highest location of demand response, and there were other locations in the system that had more value.

The same sort of thing took place for distributed generation. These are the distributed generation projects we identified on these, and they're actually all dispatched, in this particular case, they're all dispatched under the summer peak condition.

But you can see here, for example, that this one, which was the one that was the highest ranked but also the furthest away electrically, based on the analytics we concluded that that project should only operate during peak periods and should be off during minimum load periods.

And these ones that are closer in to the substation operated at the same level under all these conditions.

And if you go through the list, you'll see the list of projects that we identified throughout the system, and they're all different and they all have different operating profiles both for demand response and for distributed generation.

For the '02 system, with the '02 loads, we identified demand response at virtually every customer site as being beneficial. And then, in terms of distributed generation -- actually distributed generation was beneficial for this particular system configuration in a lot of the customer sites, but again the dispatch was different under different seasonal conditions.

In terms of benefits, we saw loss reduction ranging from 33 to 39 percent of real power losses, and 28 to 45 percent reduction in local reactive power loss as a reaction to power consumption.

The variation here is seasonal. So, for example, during some seasonal conditions it was in this range, and in some seasonal conditions it was in this range. It wasn't necessarily less during minimum load and winter peak conditions. So, again, these benefits are not limited to the highest one percent summer peak.

We also saw for this portfolio, it also delivered 117 megawatts of increased load circuit capability from the overall system. That is, the load that could be served without an overload under an N minus one contingency and also provided about 60 megawatts of peak capacity.

I showed you before that there was a big improvement in the voltage profile that eliminated all the low voltage passes and reduced the voltage variability, and then we also went through and quantified these benefits, the ones that could be quantified, or priced them, and concluded that the value of these benefits, on a per KW basis, was in the neighborhood of $450 per kilowatt present value for those additions that would operate year round.

Now we also ran some cases looking at load forecasting, and this particular utility is 2005 load forecast. Again, characterized in the system and incorporated to distribution.

And the blue line is the voltage profile as found, and what you can see here is a lot more load. This particular facility was forecasting considerable load growth. The voltage is reduced, and there's actually some places in the system where they're below .95 per unit, which would be of some concern.

The red line is the voltage profiles with the re-controls in place, and again for this particular utility what we found was that the re-controls were very effective. Re-controlling active resources in just a couple of places led to increasing voltage throughout the system.

And then we also saw an improvement from demand response, and improvement from distributed generation additions in terms of voltage profile.

We found generally that re-controls had the most effective voltage profile, and that the benefits of demand response and distributed generation really came in terms of loss reduction in capacity.

So for this '05 network, which again was for different loads and a little bit different typology, demand response was beneficial at almost every site. Distributed generation was beneficial at about half the customer locations.

And again about 40 percent reduction in real losses and about 31 percent reduction in reactive losses as a result of these projects; 47 megawatts of increased load serving capacity, and about 104 megawatts of additional system capacity.

One of the things that we had an opportunity to do, because there were actually some projects that this utility implemented, was to compare the impacts of this hypothetical portfolio with a series of transmission level network upgrades.

And we'll talk about three of them. One of the network upgrades we actually included in our base case, for the 2005 system, and then we included the other two projects as alternatives.

So anything before that we saw with the optimal DER portfolio of projects, there was a 40 percent reduction in real power losses and 31 percent reduction in reactive power consumption. This compares with this project, which actually resulted in an increase in losses.

Project three resulted in a very slight decrease in losses, and projects two and three together resulted in a smaller increase in losses. So in terms of lost benefit, the DER projects yielded more benefit.

In terms of incremental load serving

capability, I indicated before that there was about 46.7 megawatts of incremental load serving capability from these DER projects.

Project two yielded 37.5, project three yielded 38.5, and together they were 79.0, so it's in the neighborhood.

And in the incremental system capacity I indicated that these DER projects represented 104 percent, or 104 megawatts. Project three, which was a generation project, is 147. And then together --.

Now, system capacity, what I'm talking about here is system capacity in a resource adequacy sense -- people used the term earlier of system capacity in terms of the capacity of the system to serve loaded, and that would be this number.

So these projects, as a group, yielded benefits in the neighborhood of the benefits yielded by these projects, so these aren't a throwaway by any means.

And which one of these is the best really depends on what it is you're trying to get. this particular project was a voltage step-up project and probably it's real benefit had to do with reducing transmission rates for this particular utility, which of course isn't shown here.

So, my point is simply that we can compare these things side by side, the DER projects, their impacts are no inconsequential, and as a planning matter you have to do the analysis to determine which ones are really the best.

We didn't talk about voltage profile improvements, and that was actually kind of an interesting one. This again is the voltage profile with re-controls for what we call our base case project, the base case characterization of the '05 system, and that included project one, which was one of their upgrade projects.

The yellow is project two, and the red is projects two and three. And what you see here is, in terms of the voltage profile, these particular projects really don't affect voltage profile very much.

And the reason for that is because they're adding resources, these are transmission projects and they're adding resources at locations that had, where those resources don't really impact the overall voltage of the system.

And then, just for comparison, this is the voltage profile improvement from the optional DER portfolio projects. Again, they're precisely located in areas where they'll yield the most benefits, including voltage profile improvements. So that's one of the benefits that we see.

Again, for a planner, whether this voltage profile improvement is of sufficient importance to go with this set of alternatives is a matter to determine for that particular system.

I mentioned before that, for this particular system we had a lot of benefit from redistributing existing resources, so I thought this might be illustrative to take a second look at that.

What we found was, of course we were re-dispatching these individual resources on an individual basis, but then you back away and look at it, what we found was that about 64 percent of the capacitors in this system should have been changed at some point during the year, in each of these four cases that we looked at, in order to achieve those results.

About 46 percent you wouldn't change.

And so what that says to me is that about 2/3rds roughly of the capacitors in this particular system would benefit from some sort of automation.

And then we also found that all of the existing embedded generators changed their embark dispatch under at least one of the model conditions, so what that says to me -- and we found this to be even more true with the distributed generators as we added them -- that control of the reactive power output of these generators is a very valuable thing for this system, and it's one of the ways to achieve big improvements in voltage profile.

So, in terms of what you would do with this in practical terms, in my mind one of the key points here is that through this type of analysis you can determine what are the requirements for individual DER projects ahead of time.

So we can determine what the availability requirements have to be, and we can determine what time of year these projects would have to be available, and so that is easier to contract with a customer who's considering installing a project.

For example, 60 percent of the DG

projects, we found, didn't need to vary their output as we went to, among the different system conditions we looked at. So what that means is that these are good candidates for combined heat and power. They could run all year round without any impact on the system, without any adverse impact on the system.

Plus we can identify the specific locations where those projects with steady state operations are, and in some cases they may be right next to projects that should only operate during the highest summer peak hour.

Contractual requirements to achieve these types of benefits frankly would be pretty modest. The projects would have to be in the right location and more or less the same size as what we determined in the study.

We would have to be able to achieve the site-specific dispatchability profile that was described. For distributed generators the VAR output would have to be dispatchable by the network operator, within limits.

And then if the system capacity for resource adequacy purposes has value, then in order to capture the value that we monetized, that would have to go to the system operator.

And then in terms of incentives, because we quantified these benefits in dollar terms then projects in these locations could be paid a capacity payment based on the value, as long as they meet these requirements they could be paid a capacity payment based on the value that they contribute.

So, again, at this point in this two phase effort I think we can say that DER, with the right characteristics can improve network performance, that we can quantify and value those benefits, and we can compare those benefits with those of traditional network upgrades.

We can determine where these projects should be, we can determine what their operating profile needs to be, we can gain additional insight into this system by modeling it vertically by incorporating both the transmission and distribution in one system.

Certainly Aim Fast was a valid and useful tool for this application. And then, this is a study discussed more in the report, but we took a look at what the barriers to these specific projects might be, and this was some of the discussion yesterday.

For these particular projects and the type of penetration levels we're talking about, hundreds of projects within a city the size of Santa Clara, barriers remain to see those types of penetrations.

So, where we are now, and we're proceeding with another project which is in a lot of ways more ambitious but really brings this approach to a true utility scale.

Southern California Edison is the host for this second phase. We're also working with Navigant and the Department of Energy, and I'll talk a little bit in a second about Navigant's role.

The differences are, this is a major utility scale implementation. In terms of the size of the system, it's about 15 times the size and much more complex. It's also a heavily loaded part of the system, high growth, potentially some more serious system issues to deal with.

Also we're going to be dealing with network rather than just looped transmission. Certain DER devices, we're going to also look at storage devices.

And then I mentioned before typology, changeable typology. One of the things we want to look at is what the benefits in terms of system performance we could achieve from changeable typology or network typology using the existing switching that's in the Edison system.

And then we're going to also look at one measure of network performance. We're going to consider and apply a value of service approach which looks at the value of a particular addition in terms of its ability to either reduce the chances of an outage or to reduce the time it takes to recover from a given outage.

We're also going to develop what Optimal Technologies refers to as reliability optimization, and that is, we optimized the system in the results we just showed, we were optimizing the system assuming that everything was in service.

And so the question is, is there even a better optimization that says let's assume that something might go out. Can we set up the system in a way so that not only does it optimize or -- where the optimization takes into account known contingencies that might otherwise bring the system down, we'll set it up so that it can absorb the impact of those contingencies and build that criteria into the optimization.

And then the last thing, which is really sort of the heart of this project, is to look at the extent to which this type of analysis can yield solutions that achieve specific planning objectives, can we solve a given set of problems or can we achieve a certain level of performance, not just is this feasible, which was really the objective of the prior project.

And then, really the role of the Navigant piece is to look, we heard that all of the distribution planners look at candidate projects on a cost benefit basis.

So what we want to do is to expand that type of analysis to also include DER, non-wireless alternatives on an apples to apples basis within a decision model that the utility, in this case SCE, is already using.

To really demonstrate how DER could be incorporated as a normal part of their decision making process, both it's values and its unique characteristics.

And then lastly we're going to do a

field validation of the model network characteristics. It's a longer discussion, but suffice it to say there's a lot of extrapolation in these analytics, so what we're going to do is a field evaluation to see how close the assumptions and the extrapolations that we use based on the SCADA reads and so forth, how close that comes to the real field observed results.

I guess, in terms of, one of the things I was supposed to talk about is conclusions so far. We're in the early stages of this project. One of the things I will say is -- well, first of all we identified two subject systems within the SCE territory. They're probably some of the ones that SCE talked about earlier where there's some heavy load and heavy growth and there's some planning issues.

We're finding frankly that the system is more complex than we realized, the feeders are longer, there's more devices. And that's actually good news in my mind because we're developing new tools to build up these very detailed data sets that, you know, if we test them in a very demanding situation we can prove that they're really valuable in any situation.

At the same time we're also finding with Edison's system that the legacy data for their system is more accessible and more extractable, and in our case there's a lot of value in automation tools that we're developing to do this.

So, I'm going to actually skip this and let Craig talk about the ties between NPE and Navigant, and I think that's it.

MR. RAWSON: I'd like to move into the next discussion, and then we'll have Q&A on the two, because the next talk is going to talk about what Navigant is doing as a part of the second phase of this work with Southern California Edison.

For this discussion, Craig McDonald, who's a managing director with utility operations at Navigant Consulting is going to present the tool that they've developed for and are using with utilities around the country to help them with their prioritization and investment decisions. Take it away.

MR. MCDONALD: Thank you. I'm kind of reminded, a few years ago I participated in a collaborative project with the state of Florida that was run by the director of the state's energy office, and his philosophy was he never broke for lunch.

And so about a quarter to one we'd be amazed at how the stakeholders would have agreement on the issues, so --.

So I'm just going to make a few short comments. We're just getting started. My contract is in the mail. This project is just getting started, it is actually being funded by the Department of Energy, and it was an oversight that I didn't acknowledge that in the written notes there.

Basically, the objectives of our work is to evaluate distributed energy resources as a distribution upgrade. So we've heard a lot this morning about how utilities do distribution planning, looking at overload situations or critical components of the network and where do they most need projects.

Then Peter's talked about well, there's a lot of the other places where some improvements could have operational benefits. Well, how do you weigh those, how do you compare those? And even how do you compare all these various capital projects?

We had a question earlier about capital versus O&M, how do you do those comparisons. Well, decision tools have been developed to address those, and what we want to do here is look at re-conductoring, capacitor upgrades, new transformers, those kinds of things.

Or distributed energy sources, in the same kind of way as you'd look at those traditional distribution infrastructure improvements.

And so that's really what we're all about. And basically then what are the impacts of distributed energy resources on both capital and on budgets, as well as power quality and reliability.

To talk about overall how this relates to other things that are going on, one is the top box, as you can see, is Southern California Edison's baseline plans, the spending prioritization model which is in this box is being implemented at Southern Cal Edison, and then there's capital budgets and O&M budgets and baseline metrics and reliability.

New Power Technology energy net day results include distributed energy resource locations and improvements or changes in network performance.

And then the Energy Commission itself has developed a lot of data in terms of the costs and the capital costs and the O&M costs of specific distributed energy options.

As I was listening to Peter's talk it's really interesting, fascinating that there's so many locations where distributed resources provide network benefits. But then the question that keeps on coming back is, well, are those benefits worth the cost?

So that's really what we're going to be looking at in this area is that cost benefit tradeoff.

There's a value metric, and one of the things we've looked at really is how do you compare capital and O&M dollars. We heard those. That's pretty easy. But then you also have reliability, you have power quality, and you have losses. Losses, again, may be pretty easy to monetize, reliability is a lot more difficult, and power quality is quite difficult too.

But all these are considerations that are made in a project, or tradeoffs that you make.

These value metrics are used in the spending prioritization models to kind of sort capital and O&M projects, and to kind of say what projects create the most value to the system?

So we'll basically generate what we call funding curves, or which projects, capital and O&M projects, should be funded for both the baseline and the distributed energy resource cases.

So our spending prioritization model is our primary tool here. This has been developed and is being used by a number of utilities for distribution and transmission planning and increasingly actually in generation as well.

And basically, the issue it addresses is you have lots of planners, you have capital plans, you have O&M plans, you have regions one, two, three and four. They all have lots of projects, and these projects have varying mixes.

They have capital costs, they have O&M costs, they have reliability -- we've heard a lot of discussions about the number of customers that are at risk on an interruption, when you think about what's it cost if yo don't do the project.

And so, when you saw Peter put up his list, there's pages and pages long of projects.

So somebody at the technical review groups at these utilities or the capital investment committees, are facing literally hundreds of projects' requests for funding.

Well which ones should they fund? How far down there do you fund? Do we have to do them all? Which ones do we cut?

So what we're trying to do is say okay, let's create an overall objective function that takes both the quantifiable, easily quantifiable, and the not so easily quantifiable, and put all these projects in a systematic or common framework.

So all we're showing is the types of projects that you typically have in a distribution system include like load relief, and relocations, and you have reliability projects. And you have buckets of spending, you have must do's, these are the things you generally have to do because the equipment broke out and you know this load is being built out there and you've got to go and connect it.

You have little reliefs. Those are the kinds of things that get back down to your operating parameters or projects designed to improve your reliability. And you have both on capital and O&M.

So we basically look at avoided costs, preventive maintenance, customer service interruptions, and corrective maintenance, including collateral damages. And you've see pieces of all these.

The difference is now we're going to put, or what we're doing in this case is we're taking al those hundreds of projects that a typical distribution company will have and developing the same metrics for every one of those projects.

And basically we look at several types of outputs. What is the impact of spending, how is it increasing, if I spend more money how does that impact the frequency or my reliability statistics, SAEFI say.

So some companies will say we need to improve our SAEFI statistics. We aren't where we want to be, we need to improve those. How do we do that in the least cost manner.

Others say we are okay with our SAEFI statistics right now. How much can we say by optimizing our capital and O&M budgets, but without hurting our SAEFI levels?

The risk assessments, those are similar to what you've seen in presentations this morning, in terms of what's the cost, what happens to you if you don't do this project. So we have to consider not only the costs of the projects and the benefits, but what's the risk of something happening and how much that costs.

All that results in a metric, which is basically a present value of distribution system benefits. So that's this axis. This is basically, the X axis is total budget, and then present value of project costs. So we're looking at benefits and costs.

And basically, what you see is there's all new projects down at the bottom, those are the must do projects, the things you absolutely have to do. You have some projects that are kind of no-brainers that produce a huge benefit for very little expenditure.

And then you have some projects here that cost a lot and there's not a lot of benefits. The focused management decisions on where to set budget levels is really based on this area of the curve, how far up this curve do you want to go in terms of the benefits.

And I guess this draft describes that. Basically it operates, and one of the questions was what's your overall metrics? How do you weigh capital versus operating costs and as the model has been implemented at Southern California Edison it is definitely a revenue requirement, it's a ratepayer perspective.

So it is minimize the present value of costs to the ratepayers. So we consider all the general financial statistics, but we also have to consider a lot of the other things, like what the assets are that you're spending on, customer satisfaction, and reliability.

Some of the values of improving things like power quality really translate into customer satisfaction, and again that is part of the objective function is we want to maintain or improve customer satisfaction, whatever the objective is there.

The regulatory responses. Again, somebody mentioned you get a lot of penalties on certain types of outages. What's the risk of getting all those penalties or disallowances or -- and that's a cost, in this model we actually quantify that and treat that as an avoided cost.

Your failure rates, and then basically some other statistics about it. So, the main point of going through that was, we're basically trying to look at a variety of system performance parameters, project specific parameters, as well as the economic parameters.

So we're tying all those together into this, to develop those funding curves.

I was going to talk a little bit about what we do in terms of the examples of how are we valuing reliability, for example. There are a number of considerations that may go into the creation of a value metric.

And if we look at reliabilities you have the things that you think about, or maybe the cost to the customer or the cost of fixing the thing, the legal cost you might incur, the penalties and fines. If it's big enough you may also end up with an adjustment to rate base or allowed rate of return penalties, in which it becomes very big.

So, again, because everything's done on a risk-adjusted basis, you consider the probabilities of these things, the number of customers that are entered, but all these are factors that are written into or developed into a part of the overall value metrics.

And that's basically the tool we're going to be using in this. One of the main things in this project is actually valuing the power quality benefits. So what we do very well right now is the capital, the O&M, the reliability, and the losses.

As you heard from Peter talking, Peter's tools and Optimal Technology provides you a lot of insights about how you can improve the voltage profile, the power quality of the system. But what are the benefits of that and how do you trade those off.

And so that's going to be one of our focuses, is basically the valuation of that power quality metric. So that's basically what we're going to be doing in this project. We're just getting started and expect to be finished around the end of the year.

MR. RAWSON: Thank you, Craig. I'm going to ask Peter to come back up and we'll open up to questions.

MR. CLEVELAND: Hello, my name is Frances Cleveland from Utility Consulting

International. I have a question. I know this particular study was based more on planning issues, but you did mention the need for additional automation, particular capacitor bans and other things.

Is there any desire to compare real time volt var watt optimization, where you can manipulate this in real time during real time operations versus the capital expenditure for putting some of the projects in place in a more static planning environment?

MR. EVANS: Well, the approach was a planning one, so you're correct about that. I think that one of the things that came out of it was identification particularly for capacitor bands, that there's a value in automation that goes beyond, at least in the case of this particular utility, I think a handful of the capacitors were timer operated and some of them might have manipulated seasonally, but they were not really part of the real time operational toolkit of the operators.

And I think what this analysis shows, even on a very limited just pick some times during the year type of basis, that there is a value in having some automation, and then the question -- I know we talked about this a little bit on the phone -- then the question is how much more value is there in actually being able to asses things and manage things and re-dispatch things in real time?

And does real time mean within the next cycle or within the next week? And I think those are probably good questions and a good subject for more research. Actually it's one of the things I'd like to get into a little bit in the physical stuff that we do in the next phase.

But I think that one of the interesting outcomes in this is that there's a lot of value, at least in this particular system there was a lot of value for probably very little money, in re-dispatching reactive sources.

So the question is now, you know, what do we do with that? I think that's something for vendors and for system operators to think about as a tool, and is there value, does it ultimately get to the point where you really want to manage these things on a true real time basis. I'd be frankly kind of surprised if it doesn't end up there.

But I'm not sure. I think more research

is needed probably to see what the true value of that would be.

MR. SEGUIN: Rich Seguin, Detroit Edison. What was the calculation that you used? You did some power flow analysis?

MR. EVANS: We did power flow, some of the results that we got we could have gotten by just, you know, with a power flow analysis of an integrated data set you'd know not only the voltage of every point in the system but also the flows between every point in the system and the losses between every point in the system.

And so using that information we could have drilled down to some detailed conclusions. But the analytical engine we actually used was the Aim Fast engine by Optimal Technologies.

MR. SEGUIN: It was not a power flow?

MR. EVANS: Well, it's based upon the information in a power flow, but it's actually an optimization.

MR. SEGUIN: Thank you.

MS. PETRILL: Hi, Ellen Petrill from EPRI. Peter, can you explain, you showed examples of many DER projects, almost one at every customer. Do you need all those to get the value, or can you get one/630th value by having one, or, you know, and so on?

MR. EVANS: Well, first of all of course the answer would depend on the system, and I have a feeling these things would vary a lot from system to system.

The second thing is that what I didn't show you is all the sights that didn't have DER located at them where it would actually be detrimental.

And there were some in this system. Not very many for demand response, and that was mainly because demand response was limited to very small increments. But for distributed generation there were absolutely locations on this system where adding additional resources would be detrimental.

And then in terms of how much, do they all have equal weight. I think one of the things we suffered from in this system is that we were so lightly loaded that we were really, we were down to a lot of significant digits just to see differences.

And we found that under some conditions for some types of additions that about the upper third of all the ranked projects seemed to have some more value than the lower two/thirds. And that didn't surprise me that much, it was kind of an 80/20 type of tradeoff.

But I believe that if we look at a system -- and hopefully we'll find this in the next phase of the project -- if we look at a system where we're trying to resolve specific problems or address specific deficiencies, I think what we'll find os there will be a relatively short list of specific projects that have unique metrics for that particular problem and it won't be as broadcast as it appeared in this system.

This was a feasibility study, just to see if this would work. And I think looking at a system where you're saying okay, can DER solve this specific problem? And I think what we would find is that there are a specific set of projects that are specifically oriented towards that problem.

There are some others that have some value and maybe, the value may not be worth what those projects cost, so --. Does that answer your question?

MS. PETRILL: Yes.

MR. RAWSON: I'm going to ask a

question, Peter. On one of your slides you mentioned about 60 percent of the DG locations provided 90 throughout the year, and therefore dispatch wasn't as important, they can operate around the year. You said those would be the candidates for CHP.

So are you saying then that in that 60 percent of the time controllability by utilities is less of a concern?

MR. EVANS: Yeah, really both. Controllability of the real power outlet. But I think control of the reactive power outlet from all these devices is probably valuable anywhere.

MR. TOMASHEVSKY: Any other questions at all? You're free to take a lunch break. Are we looking at 1:30 or 1:45?

COMMISSIONER GEESMAN: I was going to suggest backing in to that. We're going to close at 4:00 sharp, so that I will only be one minute late to my committee meeting upstairs. So it's really, you guys have a better assessment of what we've got.

MR. TOMASHEVSKY: I think we can do it at 1:45, that'll work.

(Off the record.)

MR. RAWSON: And we're going to continue along the lines of the couple of presentations that we had just before lunch that were talking about research that's been done here in PIER, looking at new T&D modeling tools.

We're going to shift gears a little bit and talk about a couple of projects that PIER funded that looked at methods for utilities to assess the benefits of DG and renewable DG an dhow those resources can provide system benefits to the distribution system.

And so we're going to have a presentation now by Snuller Price, who some of you met yesterday, who's been doing some work for both the PIER Renewables program as well as the Energy systems Integration Group on this subject.

MR. PRICE: Thanks, Mark. As Mark mentioned, this presentation's going to be a little bit different than the presentation yesterday.

What we really wanted to do was focus down on how do you look at and assess the benefits of distributed generation on the utility system. I'm going to try to highlight a couple of parallels between the talk yesterday and the talk today, but I really also want to show a lot of details of engineering work and economics work we've been doing on distributed benefits in particular.

Where yesterday we were really looking at a range of benefits all the way up through the system of distribution transmission generation, so let's kind of focus down on the distribution system.

My company, E3, has been working on distributed generation benefits for a long time, since the late 80's. And I want to put the two projects that Mark mentioned -- and then I'm going to be talking about them in detail -- in sort of context of the evolution of the processes and the approaches that we've taken over time in the last ten years, 15 years.

And those cases are one, the renewable DG assessment project that looked at renewables in particular, as well as the Southern California Edison distribution deferral pilot project that was done under PIER through Energy Innovation Institute.

On that second project Ellen Petrill and Tom Dossey are going to get a chance to talk a lot a little bit later about the collaborative aspects of that project, and I'm going to focus on just one piece of that, which was the estimation of the value that DG provides the system.

I want to highlight methodology shifts over time, and a couple of ideas for going forward.

This is sort of a roadmap of some of the projects that E3 has been involved with over time. Before the mid-80's, a lot of the distributed energy resource evaluation -- we weren't using that word, we were using DSM -- was really based on marginal energy cost plus the CT or capacity.

So that's really a system benefit look, what are the benefits of doing DSM.

Beginning in the late 80's we started to look at this from a much sort of smaller view, and I think the first project we did was a PG&E procurement study. For those that are unfamiliar with that, a long time ago, looking at what are the distribution value? And that was a photovoltaic project.

I bring it up in par because one of the projects somebody talked about under PIER was a SMUD photovoltaic project and evaluation. I think we've come a long ways, and I wanted to kind of contrast that.

I think that the landmark study that we did was the PG&E Delta study, where we started to look at targeted energy efficiency in one area, and directly looked at that in relationship to a distribution upgrade.

So those are old, ancient history, but I wanted to kind of map how things have changed over time.

After Delta we started to develop a very sophisticated tool called Delta, which did a lot of optimization of costs and benefits, and it did a number of case studies with a very sophisticated tool that did tradeoffs of conservation, supply and demand, and then was actually dynamic, so it would look at the loads of the system at different points and change them all.

And what we found with that is that it takes a lot of work. A tool like that takes a huge amount of input data, and where we've sort of gone is to much easier screening tools that get you sort of to the right ballpark and then you do a little bit more detail. Trying to do all that detail at once, that kind of went by the wayside.

The other thing in that '92 to '95 range, and that's when I started at E3, was looking at this from an economics person's perspective. So, in terms of megawatts, if we had a planning area that needed one megawatt and we had a one megawatt generator, we were fine.

We got one megawatt of load relief, we need one megawatt, and that's going to work on our distribution system.

Beginning in about 1995 we did our first study where we found out that, well, where am I going to put that one megawatt on my distribution system? And if I put one megawatt in this spot I'll get 800 KW at my constraint, and that's not enough.

Or if I put it on this part of my system I actually get one and a half megawatts. So where within the distribution system and how the distributed generator is operating turns out to be really critical and we started to un-bundle that piece.

And the SMUD study that I talked about as part of the renewable DG assessment really integrates an engineering tool to help us look at where we're going to put the distributed generation on the system, and can we really map through with a load flow model what's going to happen to our forecasted peak loads, and how will that DG operate.

Since about 2000 we've been working on a number of pilot programs. And one of the key points I want to bring out here, and we'll see it with the assessment methodology, is we can compute a number, in terms of the value that DG might have on the distribution system for capacity.

There's a long way between computing a value of the system and going and actually implementing the project and getting the DG vendor and a contract and a process and so on.

And I think that a lot of the projects over the last three years have kind of focused in that direction, I think that was something that was really valuable about the Southern California Edison and EII project that Ellen and Tom are going to talk about later.

In the interests of time, I have a lot of slides here and I want to focus on a few key points and make sure we all get out on time, so there are a few that I'm going to gloss over a little bit, and this being one of them.

I want to talk a little bit about an overview of the Southern California Edison project, the stakeholder collaboration. I'm going to do a brief introduction and then Ellen and Tom are going to do a more extensive introduction to that project later.

Our aspect of it was to look at what's the value of the DG capacity on five example projects that Southern California Edison gave to us that they had already built.

So we looked at projects, I think they were from 2003 in terms of all the planning data, and then looked at, well if you went back and you used DG and you could get some deferral, how much would that be worth?

And the method we used for computing the distribution value was really reduced revenue requirement. So the approach that we implemented and used, we call it the present worth method, it's also called differential revenue requirement method, and it is very much how the utility panel explained it this morning.

We tried to compute what the utilities' revenue requirement is with and without the deferral, and then we look at the revenue requirement of the DG solution and its operating costs, and compare to see if, at the end of the day, what happens to the revenue requirements. Of course that amount of money is the amount that's collected in rates.

So that's really the economic perspective. I'm going to talk a little bit about how that works. It's not really a super sophisticated process. It's really the difference of two present value streams.

I want to talk about this, and I think this was brought up in the Detroit Edison presentation a little earlier. We compute it as present value revenue requirement of the base case plan -- and that's the utilities's preferred plan after they've gone through a number of options and called and got the best one that they want to do -- and then minus the present value of the deferred plan, and this is after it's delay, and then divided by the amount of load reduction needed to maintain reliability and get that deferral.

Okay, so that's really where we're getting the leverage. We're no dividing by the amount of capacity that project installs but how much DG or distribution capacity we need to get that deferral.

So in our example, if our present value revenue requirement is $10 million and we move it out a year, it will cost a little more because of inflation and so on, but it will be farther out in time so we don't have to finance it as soon and carry that capital.

So you can do a difference in present value, a $10 million plan in this example, with present value terms costs $9.5 million if you build it the next year, that's $500,000 lower revenue requirement.

If I need five megawatts to get that deferral and maintain my reliability criteria that would equal $100 per KW for that one year of deferral. And there are some subtleties to this, because expansion plans are often stated out over time and so on, but that's the basic process.

We did this for five Southern California Edison projects, and I'm going to walk through one just briefly. This is a project where their direct budget was a little over $1 million. It was to replace an upgraded transformer.

The project revenue requirement, we estimated, and including things like taxes and other indirect costs, is about $1.352 million, and that's definitely my number, not Southern California Edison's number. It's just an approximate based on an industry average between direct and total cost.

The capacity addition that they were adding with the new transformer, the upgraded transformer, was 10 MBA. The capacity needed was less than 100 hours a year, a number close to what we saw or hear earlier.

And here's the load growth forecast, at this table at the bottom. So this is KVA, the amount of load reduction needed to keep deferring the project based on their growth forecast.

So if you do that and you compute the differential revenue requirement you find out that, in this particular area, the value is about $311 per KVA for that first year.

Now what happens if you keep deferring? If you keep deferring, now not moving an investment from year one to year two but from year two to year three, and I can re-compute the value, the value of the deferral goes down a little bit, and the amount of KW that I need to install to get that deferral increases.

Also the number of hours that I would expect to have to operate my DG increases, because as I go down a load duration curve, I can expect more hours where loads are going to be over my limit as load growth occurs in the area. And so on.

So if you add all these things up, and for example we look at years one, two and three, we can get a present value of about $265 per KVA for an 880 KVA system.

Now, I said earlier that there's a long way between computing a number based on the planning data, and actually having a contract. And what is this $265. $265 is really for actually having the DG there. It's also got to run when you need it.

It also has to have some ability to be controlled between when loads are high on that feeder, it's got to come off. So there's got to be some control and so on.

We talked about the number of hours per year. This is an example for that project A, it's what's called a low duration curve. What this is is the amps on that feeder and the fractions of the year.

So this is a load profile from historical data on that feeder, and how many amps are going through it at how many hours. And you can see, a key point of this is that this is really a -- and this is not atypical at all for a distribution feeder -- it has a relatively few number of hours that have a very high load.

When we were talking about the traditional planning process at a distribution utility and load forecast, what the forecasted load is is this peak load hour. So that's the one at the very top left corner.

And the idea of course with the DG is that you could put it in and run it during those few top hours and keep yourself under capacity limit.

In the renewable DG investment project I'm going to talk about later we sort of expand that view of just the highest load hour and we actually do an hourly load flow across the course of a year. I'll show you why that matters.

So what does this mean? It means that area A DG is worth approximately $311. Does everybody notice how quickly the value of that distributed generation falls away? And that's because as years go by you need more and more distributed generation in place.

And also, as you defer a project farther and farther, that additional bit of deferral is worth less to you. So a three year contract for 880 KVA is worth about $265 KVA to customers, or about in this example $253,000.

So you can quantify this. That doesn't necessarily mean that you'd pay a contract up to $253,000. If you paid that exact amount then ratepayers would be indifferent. They wouldn't get any savings, it would just be the same cost. So you could pay up to that.

And of course the keys to capturing this value are the location, if that 880 KVA isn't at the right spot then it isn't going to be worth anything, and of course you need dispatch coordination, we talked about those.

And we did a similar analysis for five different projects, and I'm not going to dwell on the numbers, but basically what I want to point out is that the value pretty consistently falls away after years one, two three and so on.

Which is, I think, exactly why Detroit Edison was talking about being able to move the units from one spot to another and make them somewhat mobile.

The other thing that I want to point out is that the value varies a lot across areas. So we have some areas, this project B for example, who's one year value was $48 per KVA versus $311 in area A.

A couple of reasons for that. One is that, in area D you can see here, required about a megawatt in order to get back within their reliability criteria. So the denominator is a megawatt, it's a bigger number. And so you're going to end up with a lower value per KVA in installed capacity.

What this means is that those areas that have already been built up and the load is sort of trickling up slowly are going to have higher value for distributed resources than an area that's a green field and it's growing very quickly, because you need so much more DG to get any effect on your capital investment plan.

I wanted to show another example from the past. A similar type of analysis for the 200 and so PG&E distribution planning areas, and this goes back to 1994. And what this shows is the dollar per kilowatt year value for each of those distribution planning areas, across their whole service territory.

And what you find out is there are a number of distribution planning areas where there's no distribution capacity value. So what's going on in those areas is that perhaps they just built their upgrade.

And so they have lots of excess capacity, they have no projects within their ten year plan to build anything there, therefore providing additional capacity on a distribution system isn't going to get you anything.

The other thing is, you have some areas, like his one out here, I covered it up with the box, with a very high value. So, I think that variation is pretty consistent across utilities.

I'm going to switch gears now and talk about the renewable DG assessment project that we've been working on. And this project is very much focused on renewables and not necessarily a lot of the fossil-based technologies that we have been talking about before. And there are some differences and there are a lot of similarities as well.

This project was done with four California municipal utilities -- Alameda, Palo Alto, SMUD and San Francisco PUC. And the key objectives were to look at local system impacts and benefits that the municipal utility can get from having renewable DG on their systems.

We wanted to expand the evaluation methodology. It's appropriate for them to evaluate what those impacts are. And we really wanted to incorporate two things.

The first is on the bullet here, which is a lot of uncertainties that come around in planning, particularly in load growth. So we spend quite a bit of time looking at load growth uncertainty.

The other sort of -- well, let's leave it at that.

Key results from our four assessments for renewable DG were that, first of all, it's difficult to find cost-effective renewable distributed generation on a net direct benefit basis.

We've got very carefully tracked what we expected were going to be the avoided costs of the utility system operations, having a distributed generator. And looking at what are the costs.

However, we did also look at quite a bit of detail, what the indirect benefits were. And computed those based on the gap. So we would compare the gap between economic cost-effectiveness for direct costs and benefits, looked at how big that gap is, and sort of weigh it with the other indirect benefits and compare it.

And I guess Palo Alto would be a good example, where they actually had from their city board guidance where, well, we're willing to have a rate impact of this much if we can get a renewable mix in our portfolio of this much.

So then you compare, all right, how much more am I paying for renewables and is it worth it, and proceed on that basis.

The other thing I wanted to talk about is the engineering aspects of this projects, and particularly the differences of location within the distribution system and how important that is for both capacity as well as losses.

The economic stream that we did on the renewable DG assessment looks a lot like the economic cost-benefit analysis presented yesterday, for the CHP.

Similar sets of benefits and costs, and I want to kind of move through those.

We looked all the way up through the system, from the customer, distribution, transmission, generation --.

Oh, improved reliability was actually my fourth key takeaway. When we sat down for our kickoff meetings with each of the utilities and asked them well, what what their key criteria? They said reliability, we want to know what distributed generation can do for our reliability.

And so we have quite a bit of analysis here to sort of meet that, and I want to talk about some metrics that we, basically we intended to try to capture the reliability impacts.

Direct cost of renewable DG, pretty standard. The direct benefits minus the costs equals the shortfall or gap, and that's what we were comparing to the indirect benefits of renewable DG.

In terms of the indirect benefits, and some of the we quantified, in terms of dollars, and some not. But this is sort of pretty all-encompassing indirect benefits map, if you will.

And we kind of characterized them a number of ways. First was those benefits that were attributable just because it's a renewable resource.

And those would kind of fall into other categories of emission reduction value, feel-good value, fuel-related values, environmental values.

And then for each of these we actually broke down those in detail as well. Then we had a number of indirect benefits that were tied to particular technologies because of their unique characteristics.

And then we had a number of values that were just based on distributed generation, didn't have anything to do with whether they were renewable or not, but just because it's DG and it's in the right location or at the right size or something else.

So what we actually did was, for those projects that looked promising we sat down with the utility decisionmakers and just went through what they felt these were for particular projects. And that gave us guidance and a list to be able to walk through and make those tradeoffs of well, how much more does it cost, what am I getting?

Another bar chart, we saw a lot of these yesterday, so I think I'm going to kind of move on through here.

I guess I'll point out one thing here, which is we still have this issue of, and this is a CHP example from a behind the meter application, similar result to what we saw yesterday, and of course this would be a renewable fuel.

But still what we find out is this RIM test or non-participating ratepayer impact test is negative.

Uncertainty analysis is really important, because the economic screening set of assumptions that go into this really vary all across the board, so we want to be able to make sure that if we find an answer, like this is cost-effective, that the next day we get a new market price forecast and it's no longer cost-effective, we want to see how robust our answers are.

So we did that. This is that same CHP engine with renewable fuel, and life cycle net benefits. And what we're looking at here is what the range of those benefits are on the generation system or across the set of market prices in the future as we define across the range of transmission costs.

I believe this was for Palo Alto, and there's a lot of uncertainty about what their transmission costs are going to be going forward.

Distribution value -- and I'll come back to that distribution value. Capital cost of the actual unit, fuel costs, capacity factor that the generator runs, and so on.

On the distribution capacity value for Palo Alto, when we came in to this project we were expecting that it was going to be very focused on how do we capture distribution capacity value. And when we started the analysis the loads in Palo Alto were about 2/3rds of their all time peak, and that's just because of the way the economy was in 2003, 2002.

They had a lot of vacancies in their office parks and so on, and basically they didn't need any distribution capacity. So there weren't specific distribution capacity projects.

And that same thing we found true for Alameda as well. SMUD was different, SFPUC was different, but,you know, it really depends on what's happening with your loads whether or not you get any distribution capacity.

I want to talk a little bit more about the engineering analysis, because I think an important part of this is actually mapping what the DG is going to do on your system all the way through the existing engineering process that we've seen and kind of heard about today to well, is this DG really going to provide me the benefits.

And for the engineering analysis we used the, we partnered with the EPRI solutions folks, and they used their distribution system simulator software -- and this is pictures from that -- to do load flow analysis.

The modeling that we did on the load flow analysis is quite a bit different I think than typically done, because we looked not only at the peak hour but we looked at the whole year.

And the reason we looked at that is we could start to get to correlating the dispatch pattern of the DG with the loads on the system, so we could see across a range of time what it's going to be doing, and look at our reliability metrics and so on. I'll show how that works.

These are just the pictures of four different utilities in the section of them that we were looking at. Probably if you've been to Alameda you can recognize that this is the island of Alameda, and that's Bay Farm Island.

This is actually a small section of San Francisco that we were looking at. This is part of SMUD's service territory, this is to the north of us here, not too far, this is Palo Alto, this is Sand Hill Boulevard right there.

It gives you a pretty decent graphical look, the thickness of the lines, how they do with how much power is flowing through that portion of the feeder. For example here in Alameda the color has to do with which feeder it is and so on.

This is actually fairly similar I think to what Peter was talking about earlier, is that it has some optimization capability so that we can say all right, where's the best place to sight DG.

And the criteria for optimization in this example here is release capacity. So how much more load can my system serve if I put DG in the best place. This is an example for 13 and a half megawatts on this SMUD example, and it starts to just put them on there, and it will tell you where they are and what order they put them.

And then will re-compute the load flows

and so on and then you can se whether you managed your constraints.

We also looked at operational feasibility. One of the issues with DG is; two things, a voltage regulation screen, which means -- and the engineers in the room, I'm not an engineer, so they may cringe when I say this -- one of the key issues -- if I explain this wrong -- one of the key issues with DG is what happens to the voltage when it drops off, and what happens when it comes on.

And if you have a long feeder that has a relatively flat voltage profile and all of a sudden the DG goes off the voltage will come down. And you want to check to make sure the voltage doesn't come down too far. So there's some dynamic issues there.

There are similar issues with current, and current protection. So built into this tool, to make sure that the answer was feasible that we were getting, did some operational tests on voltage and current.

I want to slow down a little bit and talk about reliability and reliability metrics and the value of doing, what wee think of as a analysis towards that, and talk about how that captures renewables.

This is a stylized diagram. I think the Detroit Edison speaker had an actual one that looked very similar, in terms of when he was describing the operation of a distributor generator online.

But if one day I've got a load pattern that looks like this, and I've got my defined normal rating -- we saw some of the ways that that's defined. It's fairly standard with some differences between utilities.

And I count the energy that I serve in this area over that normal rating, we call it EEN, or energy exceeding normal, what that gives us is a measure of risk in terms of when is it, when is the load over the amount that I like for my planning criteria.

We also had a second line, which is our emergency or maximum. That's the load at which I start to actually have to turn customers off to protect equipment.

So what we can do with an hourly load flow model is compute both of these metrics in the base case, and then here it may be load has grown for a few years, so we start to exceed our emergency, and then we can do dispatch of the generator, or we can look at how the output of the PV is and re-compute these reliability metrics.

So what do you do when you get that. In our 13 and a half megawatt example in the SMUD system, what you'll find out is, here's the load in the study area that we looked at, 700 megawatts to 1,100, and our 13 and a half megawatts.

And then we computed the megawatt hours of EEN, so that's the energy over that normal line, as the load is projected to grow in the system.

If you take the difference of those two lines you get this red line, and this red line is measured on the right hand axis, which is how many megawatts am I getting as my load grows, from my units.

So, for example, if my load is at 700 megawatts and I put on my 13 and a half megawatts of DG I can actually load my system to about 715 megawatts, in this example, and get the same level of EEN.

Now, as my load grows I start to get constraints that come up in other parts of my area. And, maybe at 1,000 megawatts, my 13 and a half megawatts of DG is actually giving me about 8 megawatts of additional ability to serve load at that same liability metric.

Now let's look at the similar example, but for photovoltaics. And photovoltaics, what I've got here, this looks like about a week of the load levels at this SMUD area, and PV output. I've got the PV output here per unit, so the maximum it would export is one, but what I really want to show is the shifts.

So the PV actually starts to ramp down right about, it sort of crosses right here on the peak. The PV peaks before the system. The PV peaks maybe 2:00 p.m., 3:00 p.m., the SMUD load peaks something later, 4:00, 5:00, something like that. So I've got this sort of correlation issue.

Now if I were just using a planning criteria that said okay, what's my load reduction on my peak hour, my very peak hour, what would I get in terms of capacity of PV. And I think I would probably get very little, maybe zero.

And if, on the other hand, I look at those loads when my load is above where I'd like it to be and I re-compute it with this EEN metric, I can get a different answer.

And so here we distributed 20 megawatts of PV, I know that's a lot, 20 megawatts of PV across this area, and looked at megawatt hours of EEN, and these are dispersed sort of uniformly, what I find out with this metric is that I can serve about, in this case, 9 megawatts more of load and still end up with the same energy exceeding normal rating.

So what I'm saying is that there are loads in the mid-afternoon that could also cause problems that PV is helping, it may not be helping on that single highest hour.

And some of the advantages of doing that type of analysis, you can start to look at that.

I wanted to close up by just talking about another few things that we've been working on, and maybe point out. One is that, we talked earlier about the N minus one criteria as sort of the established industry benchmark for investing and building new distribution capacity.

And the problem with N minus one criteria when you start looking at distributed energy resources is what is the N? I put in a DG unit, is that equal to the same reliability as the new line? No, probably not, maybe it is maybe it isn't.

The point is, N minus one is a criteria that's been used for a long time to compare very similar types of resources, a new distribution feeder, a new substation, what have you. And when you start to mix lots of different types of things together it's not clear exactly what reliability N minus one will give you with DG.

And so we've been working on a number of projects that look at that reliability in some detail, and really what we're looking at is equivalent reliability. So how much DG do I need for equivalent reliability to what I had before without DG.

And one thing that can look like is redundant DER units. So, for example, if my forced outage rate of my DG is five percent, then I might buy two or three of them, and I can get the same reliability.

Or, in California what we've done is, we've talked about physical assurance, so if the DG doesn't start then customer's load goes down. The redundant DER approach, we're looking at that, mostly in New York state, under their DG pilot project, as an approach. Physical approach is more of a California issue.

And I just want to point out, this reliability criteria is going to be important to make sure that we know what we're doing, what the reliability of the system is going to be.

Equivalent reliability methodology, this is a lot of words on here. I guess the point is, I'm going to jump to the middle, to define a level of reliability that we like, not a planning metric like N minus one, but something like I want five 9's, or I want four 9's, or what have you.

And then look at the combined probability of meeting that load with a combination of resources.

We've done this, I've got a stylized diagram of the approach we used to do this, it was actually a pretty complicated project, for Con Edison in part of Manhattan, to look at all the different resources, what was going to be available to meet a very stringent reliability criteria.

We used this markoff chain approach, and I don't think we need to go all the way through it, but what we did in sort of a nutshell was to define states of each of the pieces of equipment that supply the load, how long it takes to repair them, how long they fail, and then compute basically the amount of time we spend in acceptable states of the world and the amount of time we spend in non-acceptable states of the world, and try to get the acceptable states p to our five 9's criteria.

For anybody that's tried to do this, this is a pretty challenging type of exercise. The markoff approach methodology I think came out of designing redundancy for nuclear power plants and tracing through all the equipment and probability failures of all that. I'm not a nuclear engineer, but it's pretty complex.

Sort of a simplified version of that, if you look at this redundancy idea, this table was built for competitive solicitation to purchase DG capacity and try to get to five 9's.

So, in a nutshell, if you were to bid and you were to aggregate together ten generators, and you wanted to get to this five 9's, if each of your generators was 95 percent available, what that would mean is that the firm capacity that you're actually providing the system is your ten generators minus your two smallest minus your two largest for six generators, and the capacity rating on their six middle sized generators we're estimating as firm capacity equivalent to the reliability of the distribution system.

If you do that type of thing you end up with a diagram that looks like this. If you needed 14 megawatts and you were going to install that with, say, 500 KW units, what that actually means is that you need about 16 and a half megawatts, in this example.

And if you are going to use 30 KW microturbines in a lot of them you actually end up needing less capacity in terms of redundancy because you have so many little units that you want need to install so many, and so on.

I wanted to talk a little bit about most recent projects and ideas for future work. I'm not sure it was clear that when we compute the value on distribution vale as we did for the Southern California Edison example, and we end up with this number of, you know, how much is it worth to customers, that's not the last thing you need to do.

There's a whole lot of work that needs

to be done to actually capture that value, and to actually get that capital deferral and to actually make that happen, and I think that going forward a focus on implementation of that and real world projects, establishing metrics so that we know what reliability is going to be that we're getting, and trying to standardize a bit, are really sort of the next steps as I see it, for us, and I'll end on that.

MR. RAWSON: Thanks, Snuller, were there any questions?

COMMISSIONER GEESMAN: Going back to that PG&E slide from the beginning, I believe there were something on the order of 200 some odd planning areas. How static is that ranking? If you broke it into quartiles how likely would the planning area be to be in the same quartile next year?

MR. PRICE: Yeah, next year, maybe somewhat likely. But if we were to re-do this now, for example, I think it would be a completely different set of areas.

And that's because these high cost areas are areas that the PG&E distribution engineers have probably upgraded. And then they're going to come back down here to the stack, until load grows in that area, and so on.

COMMISSIONER GEESMAN: To the extent that you're looking at incentive payments or benefit payments to DG from deferral, you're compressed pretty tightly in time, aren't you?

MR. PRICE: Yes, you really are. Let's just look at an example, like area F that we looked at for Southern California Edison this year. That first year in this area, if you keep deferring you get a pretty high value, and you can start to do a program and so on, for that area.

Here it rises, and then we have a big load come on, and now I've got a much lower value to play with. So we've really got this sort of three year window that we've been working with on most of our studies to sort of try to get something there, and I think the mobility that we saw, in terms of being able to make these mobile that we saw from Detroit Edison and so on are really because of that.

COMMISSIONER GEESMAN: Thank you.

MR. RAWSON: We have time for one question, or we'll move on?

MR. SEGUIN: Point of clarification. At

Detroit Edison we've got 3,000 circuits, and I figure we've got about 100 in difficulty, and we spend a lot of money on it and whine about it and etc. We forget that we've got 2,900 doing pretty well. I mean, we do a pretty good job.

So all you distribution engineers, give yourself a hand. I'm saying that because it's relative to that curve, but we work pretty hard at the end, and I think it kind of marches around. I'd just like to put it into perspective.

MR. RAWSON: Thanks, Snu. As Snu indicated we're going to continue now and talk a little bit about the distribution control pilot project that Edison's been working on with, formally EII, EPRI.

And Ellen Petrill's going to talk about the collaborative aspect of that, and what was learned through the collaborative process.

And then Tom's going to talk, on the second part of this discussion, about where Edison's heading with this project.

MS. PETRILL: Okay. Hi. Thanks to Mark and Scott and Commissioner Geesman and Melissa and the rest of you for hanging in there until the bitter end. We still have a little ways to go, so let me get this going quickly and touch on the highlights.

This is a description of a pilot project that came out of the EPRI, originally EII, DER public/private partnership, which was a stakeholder driven, is a stakeholder driven program to look for the win win win, so ways that we can apply distributed energy resources that provide value to the one who buys it, and the power delivery system and other ratepayers as well.

And if that all works then society benefits as well. So we're looking for the win win win. And I want to say thank you to the California Energy Commission, who is the major funder of that work.

And the team, Snu and John Minnoms and Jim Torpey and Dan Rastler, and Southern California Edison who, without that team we wouldn't have gotten where we are.

And I'd like to say that Southern California Edison is a very enlightened utility, and forward thinking, and has a really good team of Stephanie Hamilton and Tom Dossey, and we worked with Ishtiaq Chisti and Dan Tunnicliff, who really grasped the idea of let's make this win win win, and brought their company along too.

So we had a lot of movement as a result of stakeholder collaboration. And we used stakeholder collaboration to address a micro issue, which I think is DG and distribution planning, as you said today, Commissioner Geesman.

But I think that the stakeholder collaboration approach is also a way that we can address the macro issue of how do we integrate distributed energy resources in our power deliver system, either on the customer side or the utility side.

There's a lot of issues, there's a lot of smart people who have been working on this. And I think if we can get together we can develop a way to move forward.

So you challenged us yesterday to come up with a solution or else we're going to get an out of control approach, and I think we can come up with a solution with the stakeholders, like we had yesterday and today.

So I'd like to show you how it worked in this micro slice of what we did, so I'm going to describe this project, focus in on the key issues and how we overcame them, and give some recommendations for going forward.

This is a pilot project of the partnership. Our goal is to help Southern California Edison to develop an RFP -- and actually Tom Dossey's going to tell you that it's not really an RFP, and I'm really happy about that, because I think that's movement too -- how we can yield successful proposals.

Probably you've all heard about the New York situation, where the utilities in New York were asked to solicit DG for distribution planing as well, and they had several RFP processes, and we know a few proposals were submitted, no projects went into place.

And we understand that a lot of that was because the RFP was just not very inviting. Southern California Edison really wanted to make this successful, so they invited us to work with them to bring stakeholders in to help them understand what would make a package that someone would be interested in participating in. So the goal is to help them.

Our objectives were to task our stakeholder collaboration process, use this as a test of that, look for the win win solutions, and develop a scalable process that we could use in other places in California or in a broader way, or in other states.

And the approach is that we did a lot of what we did this morning. We learned about distribution planning and potential win wins with the stakeholders in workshops, we identified issues that the stakeholders came up with that needed to be worked on, and then we spent some time in working groups focusing on those issues.

We provided input to the development of their solicitation package. And then the idea is to monitor the results and report. Well, we haven't had a solicitation yet -- which Tom will talk about -- because the planning process is taking a little bit longer.

But we expect to pretty soon and we'll be able to monitor what goes on. And so far the outcomes are that the DG community really learned about what distribution planning takes, I think their eyes were opened.

And Edison changed its approach on many issues, things that they just hadn't thought about before. And again, as I said, we don't have final results on the RFP, but we do have a model agreement and I think a number of breakthrough issues, breakthrough results.

Let me tell you about the process. We had an opening workshop where we invited stakeholders to come, and they were manufacturers, developers, other utilities. We also got support from DTE, so Rich and Hawk Asgeirsson were also part of our process in the working group.

We had some advisers, which were Mark Rawson from CEC, and some people from Massachusetts came and participated, and other utilities also.

And what's not written here on the slide is we had a reception before we started, with some drinks, and we also had an executive from Southern California Edison who came and talked about how important the process was to Edison.

So it made it very clear that the company was behind the process. We got to know each other. We talked about our kids, and what we do outside of work, so that we, you know, we started to build some trust and understanding of each other, and that's part of this whole process I think.

And then we spent a day talking about what we each do. So the stakeholders talked about what their needs and interests are. And then we talked about well, okay, what are the issues. And everybody signed up to be on an issues group.

So we put the issues into two buckets, and everyone chose a bucket to be part of, and help work out what the issues were. And we spent several weeks on the phone and people did homework to go in and think about what solutions could be, and come back and contribute to the solutions. And we came up with some really great solutions.

And reconvened again, had another reception, another dinner, got even closer, and got through some issues on the second workshop that we hadn't resolved, and came up with some I think really great responses.

So here's the issues, and I kind of prioritized these on how I think they impacted the outcomes. So these were the potential show stoppers.

The first one was, the first out of the box approach to what would the solicitation be was there would be no dollar amount for how much Edison would be willing to pay for the distribution service of a DG located at a customer's site.

And the thought was that if you put in a dollar amount then everybody would bid up to that amount, and we wouldn't get a real competitive bidding process.

The DG manufacturer and developer said there's no way I'm going to put any time or effort into this unless I know how much it's worth. So after a lot of going back and forth Edison said okay, if we really want proposals we'll have to offer that. So they did.

So they came up with a market reference price, based on what Snu just talked about, the carrying costs of capital for the deferral.

And it doesn't mean they would pay that, but it would be kind of the reference, so a proposer would know whether it was worthwhile for them to do or not.

I keep using the word "bid" and I don't mean to because it's a much more complicated process than a bid, so it was really a proposal.

The next issue was physical assurance. I think you all know what that means, I'm not going to spend a lot of time on it. But it didn't mean that the unit had to be operating for 24 hours a day seven days a week; the answer was -- after we talked about it -- the answer was no, it's just during the hours of time where there was an issue that the deferral was needed.

So it was about 200 to 400 hours a year, and it was going to be decided by contract between the customer where the DG was going to be sited and the utility.

And after a lot of discussion and a lot of internal work by Southern California Edison, they turned this whole process into not a generation requirement, but a demand limitation for the customer.

So it became not a focus of is the DG operating, is it performing as we expected, is it reliable and all that, it's the customer is going to operating to a level that they affirm, a demand limitation level that's written into the contract.

And I thought that was a huge breakthrough and a lot of innovation by stakeholder groups talking about what they wanted and what customers would live with and what the utility came up with.

How much distribution system data would

there be? At first it didn't seem like there'd be very much, and again that wasn't going to be very useful, so Edison said yes, they'd put in lots of information, as much as you needed, as long as you signed a non-disclosure agreement, and actually that didn't seem to be all that important.

But the two step process sounds like it's going to be really workable, and there's going to be all the information needed.

Another show stopper that's remaining, unfortunately, is the self-gen incentive program. We thought that maybe the proposers could get access to that incentive program as well as the distribution service payment.

The self-gen incentive program doesn't allow payment for other services as well as the SGIP, so it looks like, if there's a DG proposal going in and they're going to look at getting the distribution incentive payment, or the self-gen payment, the SGIP payment is much bigger in most cases than this one. So it's probably going to hurt this a little bit.

And we'd like to take that on, so maybe that's a thing that you can put into the report, a proposal that these programs could work together.

However, one of the outcomes of the CHP work that we talked about yesterday was that DG should really be paid for incentives, not just -- paid for its services, not just incentives that come out of public programs.

So that could be a show stopper, we'll see what happens.

Additional DG values. Yes, there could be payments for curtailment or DER.

Okay, so again let me just summarize. The deferral value, so a dollar value in the package, and the physical assurance, those were big findings that came out of this, big achievements.

Some specific issues. How do we simplify the process? After a lot of work by the issue group we came up with a much simpler, less onerous model agreement and a reasonable process.

Could you use DG and demand response? Yes, you could. And that was, I think another innovation. But we decided, because the order from the PUC said "distributed generation" that we had to have some DG there.

And we said it had to cover critical loads, but that would be defined by the customer.

So we'll see how that comes out too.

There is always this problem of only two or three years of deferment. Well, we probably can't get over that, for the reasons that Snu described in the calculations, it's just not worth that much.

But you could have an option to renew if the decision was made not to make the traditional upgrade.

And, another big breakthrough, I think, was that SCE said they would facilitate interactions between customers and suppliers. So rather than just throwing information out they would help bring customers and suppliers together in fairs, or some kind of interaction. And that was really a good outcome.

A couple of broader issues. Are there alternatives to the RFP process? Like could you use feeder specific tariffs or even broader territory distribution credits or tariffs. And we couldn't address that in this pilot project, but Tom is already thinking about that you could go broader.

So I think that the discussions and interactions have already made people think about broader ways to go forward here.

And on the big question about a business model, is there a broader business model, is there a role for the distribution utilities to be proactive facilitators, is there a way that we can incent the utilities to take a more proactive approach?

Well, again, this pilot can't really address that, but the conversation's started. And we can make some progress through stakeholder collaboration.

So here's the recommended process. There's going to be a request for interest and qualifications, and then Edison will select qualified respondents and inform customers on the feeders where there's issues of those qualified respondents.

Then a package would be released with detailed data. Edison will facilitate the customer and developer or supplier interactions. Proposals will come in, we hope.

And then Edison will negotiate with the customer. So it won't be a sealed bid that you take or leave, but because these are agreements with customers, Edison wants to work closely with their customers and make something work that's a benefit to all.

Conclusions. Stakeholders can resolve show stoppers, through collaboration. And informal collaboration in this kind of working group process really brings out innovation. It takes awhile, because people really need to come around and they can learn and listen and they can hear other people's points of view.

And we all had a fun time working together and coming up with some innovations and solutions. So I think stakeholders can really work, and we had thee major achievements, that the customer agreement will be for demand limitation, not generation, and there will be a market reference price and detailed data in the solicitation package.

The distribution deferral value can be small. What snu showed was kind of intriguing, $250,000 was not bad. But it could be small and it's probably not enough to make the project go, but it could be gravy to push it over the balance so a customer would want to do the project.

And the solicitation process, the RFP process, can be cumbersome and costly, so we probably don't want to get stuck in that mod all the time. But i think Tom's already thinking about, Edison's already thinking about new ways to move forward.

And there are some outstanding issues. I mean, the big one is will customers propose. Will customers agree to have a demand limitation agreement, even if it's only 200 to 400 hours a year. We don't know that yet.

And is this an effective route, to include DER and distribution planing. I think it's a micro solution to this whole issue, it's possible.

And our stakeholders said, to really integrate DER into the power delivery system we need to make sure we capture all sources of value. It's what Commissioner Boyd said yesterday, let's increase the list of benefits. So let's make sure we can capture those, and there's some value to them.

Let's try to simplify the process. I think we're down the road toward that, but I think there's ways to go. Let's proactively plan for and integrate distributed energy resources, and that means not just generation but demand response and energy efficiency.

Are there ways that we can incent all the stakeholders to participate when it's a value for society?

Can we -- and I think this is the big one -- adjust the regulated business model. You know, our regulated business has set up, over the last 100 years, to work in a way that we're moving away from. So can we change that model to make it work for these new innovative ideas?

And the stakeholders said continue to use this stakeholder collaborative approach, because it can work to bring change.

So I'll conclude on that note. And there's more information in that package. And our website has all the workshop materials and the process. Thank you.

MR. RAWSON: What I'd like to do is I'd like to have Tom present his part of it, and then maybe we'll do questions and answers for the two of them at the conclusion.

MR. DOSSEY: Thank you, Mark. After everbody else has presented today, my role is to answer questions. Anything that I'm going to present is probably just a clarification of what we really have already covered in some form or another today.

You know, this all started with the CPUC order that said that utilities were to consider DG in our distribution planning process. And we've all struggled with that, San Diego, PG&E and Edison.

And I think we started off with thinking we were going to install generators, to have somebody install generators to support our system.

The criteria set in that order was, as Scott provided earlier this morning, is that this DG alternative must be located in the right place, have enough capacity, be installed and in operation during the time that the utility needs this, and then provide this physical assurance.

Physical assurance could be defined, as Snu said, as either redundancy or maybe some type of demand limitation or load control of a customer. First of all, we're talking about distribution systems here too, that's something else that's clarified in point, is that this is deferring upgrades to the utilities' distribution systems.

And I've taken that and I think most of

us would look at, for what we would consider DG technologies, as things that would be supplied by our low voltage systems -- the 12, the 16, the 21 KV, whatever the utilities are operating on.

So again, on this chart, it's the smaller poles and wires rather than the transmission systems that we're talking about.

Now, this issue of locating them in the right place. This slide here shows a proposed project by a utility that is the substation, the getaway cable out of a substation are the cable that exits a substation.

Often that is the pitch point on a circuit, a distribution circuit, that gets overloaded when the capacity of a circuit -- this is just a very simplified diagram of a circuit. If the problem is that this substation exit cable was overloaded ,you could put generation anywhere beyond it in the circuit.

So we were looking for using customer generation or generation provided by the utility could be located fairly much anywhere out on the circuit.

On the other hand, if the project that you were looking at was a section of cable or overhead line further out in the circuit, that first location, where it was just beyond the cable, would not work.

So only customers beyond the upgrade in this particular circuit could qualify for participating in this deferral. So again, you have to be very selective on where the customer would have generation that would be helping the distribution circuit is located. I think we talked about that earlier.

Another point to know is that it takes quite a bit of distributed generation to defer a project on the typical utility distribution line. We talked about 400 amps as a typical loading value for 12 and 16 KV lines, and that the 600 amp is really the maximum or the emergency rating on them. That's what their designed, at their high end.

You translate these amps back and forth to megawatts you can get an idea. And again remember a typical Dg project may be a megawatt or less. Very large ones are typically under five on the distribution circuits.

We've got a few older four KV circuits, I think all the utilities do. Detroit Edison has a significantly larger percentage I believe, and you seem to have a lot of your projects on your 4.8 KV systems which, less a smaller amount of capacity can do more good than on the higher.

The other thing is when you come up to thinking about deferring it, transformer bank back to the substation, our typical banks are rated at 28 MBA, that is from the 66 or 115 KV down to 12. So deferring a transformer bank takes quite a bit of distributed generation, it's probably not practical, probably won't happen.

This would be just a little bit of a guide as far as how much would be needed on 4 KV lines, 12 and 16. Again, the point here is that it's going to take a significant amount, either at a single location or at a few locations, two or three customers with two or one or any combination, to defer an upgrade project, to be worthwhile to the companies.

We've gone over this in different forms today, as far as forecasting how the load growth is going to happen, and how it can happen. I've got a simplified graph here, using a straight line. The line could be curved, depending on the growth in the area.

And the point for using this is that, I think that the utility planners would have to presume that the generation is typically not on at the peak time.

I think that would be the way that most planners have done it at this point, since the utilities don't have control over customer generation we more or less subtract it out of our forecast, we don't presume for it to be online.

So what we're doing here with a demand limitation agreement is getting control over that customer generation or over that customer's ability to manage their own loads and reduce their loads if their generator wasn't on at the time.

The other thing that you can see in this graph is that as time goes on, that's why these contracts would be typically short-lived, one, two, or maybe three years, it's the fact that as load continues to grow that particular DG site probably won't have enough capacity to continue to keep up with it, and eventually the circuit will have to be built or upgraded or changed.

And at that time, you really can't justify paying the DG partner for deferring something that you've built, you know, it's based on the savings. So that's just another way to look at what you've already heard today.

This physical assurance issue simplifies the administration of this quite a bit in that the contract will provide for the customer to put some type of controls on their main breaker or their main breakers, maybe they'd have one or two services, that would be a low set circuit breaker that, whatever that level that they would contract to, typically it would be the level with their generator on, and that level will have to match the utilities' needs for reducing the capacity on their circuit in order to get their deferment.

So this is where the negotiation goes back and forth. The fact of it is that there is a physical control on the customer's circuit that would reduce that customer's load or turn that customer off should their generator not be on during the time the utility needs that capacity.

Remember, we are planning to upgrade our distribution circuit. The customer that wants to participate and receive that incentive payment for this says "no, no don't do that, let me take care of you" and that way you can save money in upgrading the circuit.

If that's true that customer has to be there, because at the point that we're going to use this somebody's going to get turned off. If it's not the customer it would be some other customer or some other group of customers.

But because this is a demand limitation agreement, because that customer has distributed generation, typically nobody gets turned off. Everybody's happy, the customer's generator is on, his operation continues, all the customers are happy, life is good.

It's only if that customer's generator should fail during these few hours a year that we are having problems.

Again, talking about the few hours a year, and you've seen this curve in a few forms today, I'm thinking that it's virtually always going to be less than 200 hours per year that we would have to turn on this demand limitation device.

And that would be done remotely. The utility would have some kind of communication equipment to customer's equipment that would set this up to turn it on to limit the demand for those hours.

And that demand limitation, because of the terms of the contract, would only be done when that section of the distribution system was at this loading point that we had contracted for.

So if the distribution system was able to carry load without having to turn this on, the utility should not turn on. This isn't a multiple purpose load limitation agreement, it's for deferring that.

Ellen talked about being able to participate in multiple programs. These customers could also sign up under interruptible programs and receive a separate benefit for that. So, you know, you could get rebates from two or three.

She also talked about the SGIP, the self generation incentive program. It is that program that has the restrictions in it that says if a customer participates in this program it can't receive benefits under the SGIP. We don't have limitations here for that, but at this time you couldn't get incentives from both.

Moving on. Trying to get around to how quickly can we get this in place. You heard this morning that there's like an 18 month planning cycle from the time that you can see that you need something to where when it would go online.

So we're going out this year, as we're going over this little timeline here, we'd be looking to try to defer projects that would have a 2007 operating date. The reason that we'd have to start now is that, in order to provide the maximum incentive the utilities can't spend any money on providing this upgrade.

So if we have to start buying the equipment or buying the land or whatever it is that you would need to do to provide the upgrade, that's going to be some cost that will reduce the amount of capital available, and should re-calculate your incentive paid to the customer on.

There could be ways around that, but typically it's going to take the 18 months, because of either misunderstandings or difference in timing in our distribution planning cycle. I'd say we're a little bit behind the curve right now and we're going to have to work very hard this summer to get all the pieces in place in order to defer projects for 2007.

This is also going to be kind of a detriment in trying to market this to customers, in that we're asking them to commit a year and a half in advance to something down the road. A lot of customers, I suspect, won't have that kind of planning window in their own mind and will not want to fool around with this, but we're going to have to actively market it.

I think we've talked over this today. As far as the requirements going through the planning on how to identify the locations in our system that would be prospectives.

And that would have to have a capacity requirement that we feel that a customer with DG could address, and it would have to have some cost that would be worthwhile to the company that would provide the incentive to the customer for them to want to participate.

And the other thing is that if the project that we're proposing is something that is really a requirement and it could be a maintenance project that, having our customer agree to defer the line really couldn't do.

If you had, using a transformer example, if you had a transformer that was leaking and our project was to replace the transformer, that's going to have to be done regardless of whether there's a customer out there willing to defer the capacity.

The same thing could be with damaged cables. Your plan could be to replace those for maintenance purposes rather than just for the capacity need.

Other things that happen is that we make tie lines between one circuit and another, and sometimes those tie lines are required for operating convenience, and again, DG may not be able to avoid that.

So each one has to be evaluated on a case by case basis. Again, we're talking about customers. We'll be screening customers -- and I think it's only the utility that can do this -- to try to identify their customers that have an adequate amount of capacity and the potential to use DG, that would be those you should approach to say hey, let's try to work out a deal.

Either you already have DG that we would like to tap into the capacity that we have, or you might be a good candidate for a DG project.

Again, just graphically here, if we go back to that first situation, the first case that we talked about, the getaway cable out at the substation, we could approach any customer on that line that had enough capacity, but if the project was at some other location you may not be able to locate those customers.

The other point, you see the tie pointing at the top, the switch that could be closed. It could be you could find a customer on an adjacent line that could be used with some switching or reconfiguration of your distribution system that more customers then are exactly served on this particular line could be used.

So I think utilities will have some flexibility, as far as approaching customers.

This is where we get into the RFP process, or the solicitation. We initially talked about RFP's because that's what everybody else is doing, you know, you issue an RFP.

The fact of it is that I think we're going to have so few customers at any one location on our system that it probably would be better to have one on one solicitation negotiations with them.

I'm going to be very happy to find a circuit that has two customers that could compete with each other for deferring an upgrade.

First of all, we probably only have

about 60 circuits in any one year that are nominated for upgrades. And on those circuits we're looking for two or three megawatts of customer.

And we did kind of a data evaluation last week and find that we only have, out of our four million customers, 600 customers with over 1.5 megawatts of load served on the distribution system. So again it's a limited customer base that can do it, and of those 600 customers many of them may not be suitable for DG-type facilities, they may be facilities that couldn't use a combined heat and power type system.

We talked about providing information to the vendor base. You know, I think that we as the utility will be soliciting customers. We'd also like to have our DG suppliers have an opportunity to do their own marketing and address this.

So as we go through and identify locations that seem to have prospects we will make this information available to the DG community, if you will, installers, suppliers, and manufacturers, and offer them non-disclosure agreements. And in return for that I think that we can disclose quite a bit of information to them.

There's a lot of reasons why we could consider this information proprietary, but primarily it's just for security of the information in our system that we just wouldn't be posting this on the Internet to have everybody see how the lines are set up and in what capacity, where the weak points are on our system.

But I think that could be shared with many legitimate DG suppliers, so that they could have an interest and be able to participate in marketing our equipment to those areas on our system that have a requirement, or have a need.

i've talked about this already, as far as depending on the numbers of customers we'd see on a circuit as to how we'd approach that. And again, if we had multiple customers an RFP would be a good method. If there's only one customer out there it's probably not the right method to approach them.

Another point is that we have a service, I guess this could be contentious at times but, any customer that would like to come to Edison and say "you know, I'm considering DG" or "I'd like to participate in the program", we have people that will help them with the economics of it and see if DG, combined heat and power, peak shaving, or whatever is a good economic choice for them at that location.

And we can factor in the incentive or the potential incentive that we might have in order to help them make up their own choice.

DG suppliers, manufacturers and installers also have that option of helping customers make that evaluation of seeing if DG is good for them. This is probably just another good marketing point of saying "and there's incentives available too."

Getting into the agreements that we worked out, that Ellen had talked about. These agreements will always be between the utility and the customers, we really can't do this with a third party or a DG supplier because the physical assurance would always be a burden that the customer would have to take on. It's their service that would be limited during these times in order to make this work.

And each location would have different terms and conditions and prices. that's another point, it's kind of a one on one type negotiation because of the locational requirements, because of the nature of the upgrade ,the capacity required, the amount of hours per year, all of that will be affected.

And in the agreement, in order to protect the customers' rights, will be the specific limitations on when this demand limitation will be turned on, the number of hours, and years, and the cause that would initiate that demand limitation.

So that gives some assurances to both parties, and let's them know what they're getting in the deal.

Again, another point that I think was important was that we were going to have the customers provide their own physical assurance control hardware. We will provide a communication device to it that will turn it on an doff, but this reduces the cost to the customer.

The utility will l have control, the ability to prove the design of the equipment, but each customer will have a different installation, and as long as it's acceptable to the utility it would be something that they would design and install and operate their own equipment.

And the performance payments, or the incentive payments paid to the utility through the customer are based on a formula that was set by the Commission in their Order, that'll probably get you a lease commission.

And one point for this is that the payments for this would not be enough incentive, but hopefully a pay as you go. Hopefully the customers would want to continue with the contract for the entire term, and so we'd find some way to allocate the money on a monthly basis.

I don't think this would be worthwhile for either party, the utility or the customer, because of the cost of the communication systems and the demand limitation system, to sign up for an agreement that was for much less than two years.

If it could go for three or four years that would be great, but uncertainties in planning and expectations for load growth will probably keep it in the two or three year range. That's probably what should be expected.

And with that I think I'm at the end of repeating. So, questions? And Ellen, maybe you could come up and --?

MR. RAWSON: Were there any questions on the dates?

COMMISSIONER GEESMAN: I just had one. I think your timeline allocates six weeks for contract negotiations.

MR. DOSSEY: The contract we have filed with the Public Utilities Commission, it's more or less we have a model contract file, so the terms of the conditions will be available initially.

COMMISSIONER GEESMAN: That's where I was headed with that. You're obviously going to have to standardize a fair number of those in order to fit that time frame.

MR. DOSSEY: Yes, yes, and there's only a few terms and conditions that really have to be negotiated.

COMMISSIONER GEESMAN: Okay.

MS. TURNBULL: Jane Turnbull, League of Women Voters. First of all, I'd like to commend EPRI for being innovative and taking a big step forward with this project. I think it's a really good endeavor.

And also I'd like to commend SCE for thinking outside of the utility box, because that box is sometimes very constrained.

But, to some extent, the League is enthusiastic about distributed energy because we feel it fosters conservation, and because it's likely to encourage renewable energy. We also realize that reliability of the system is pretty important and we certainly want to foster that as well.

I do have concerns about demand limitations. Because if you are going to be encouraging conservation and renewables, you really want to encourage them more than 200 hours out of the year.

And I also am concerned about your concern about incentive payments, because we think incentive payments are a short-term inducement for people to move ahead. We do think that value-based payments really are the way to go, and I think that certainly distributed generation has values.

One of the things I learned today was the extent to which these values vary year to year, and I think that's going to be a real complication. But I do think that values are, you know, the credits ought to go to whoever puts in in distributed generation.

And I'd like to get your comments in terms of how you think that a program like this would encourage CHP and/or renewables?

MR. DOSSEY: It'll encourage CHP in that in that it will provide somebody contemplating installing a new system and willing to participate in this demand limitation an additional value payment to them, for the one or two years that they would come online.

It also allows people with existing systems either to expand their systems in order to participate or to at least find some additional value in their system that this payment would be made back to them.

I call it an incentive, it's not really a rebate nor an incentive, but it is a payment for performance. They are taking on an obligation to limit their demand for a certain number of hours per year because they already have a system that allows them to do that.

They don't, we're not trying to pay for the entire cost of the generation and installation, we're only paying them for limiting the demand that they present to our system for a few hours per year. Their having that generation allows them to do that, so it can sweeten the deal for a new project and it can provide some additional value for an existing project.

This program isn't necessarily going to encourage conservation. We have other programs that do address those issues.

What we are looking for here is letting a customer that has a megawatt of generation and wants to sign up for a megawatt and a half a demand reduction, or a demand limitation, to allow them to participate.

The program was initially developed to inspire, I believe, installation of new distributed generation, and not necessarily demand response programs. But there's no reason why in sense the requirement is really only for limiting or demand, the customer can't use both demand response and DG.

To show good faith they should have a substantial amount of DG and not just a token generator. So that's where we're headed for that.

MS. TURNBULL: Sounds good.

MR. EYER: Tom, did I understand you to say that aggregators, for example, will not be able to play this game? It will be bilateral agreements exclusively, as we see it now?

MR. DOSSEY: Yes. Aggregators can participate in working with customers and helping the customer understand, but the agreement would be between the utility and the customer.

MS. PETRILL: Because of the physical assurance.

MR. DOSSEY: Yes.

MR. CLEVELAND: I'm curious to know if you would allow a customer to actually locate the DER somewhere else that may be more beneficial to you but still have that agreement with you for say, the two years, and then maybe re-locate it behind his point of common coupling later on?

MR. DOSSEY: if the customer and the DER were located at the same point, or at a point on that particular circuit?

MR. CLEVELAND: Yeah, on the same circuit, maybe closer to the substation.

MR. DOSSEY: I think that would work, and that would allow an independent generator who wanted to come and somehow install a generator in the circuit, partnering then with a customer who would take on the demand limitation, that's possible.

I didn't see enough of a market in that to try and spell it out, but we would consider that.

MR. CLEVELAND: Thanks.

MS. PETRILL: There's an innovation right there.

MR. SEGUIN: Does that mean you'll allow sellback?

MR. DOSSEY: We allow sellback today. Customers have always been able to sell power.

MR. SEGUIN: As part of this program?

MR. DOSSEY: Well, it's not as part of this program, it would be a customer with generation that is selling through the ISO. I said allow sellback, and it is allowed. Most customers who are generators of this size choose not to try to deal with the ISO, but it is possible and it is legal, and then could participate in this program.

MR. SEGUIN: So if they had a megawatt and a half worth of load, and you needed two megawatts worth of relief, they could put in an additional half megawatt of generation and offer you sellback of half a megawatt, as long as they can get it through the ISO?

MR. DOSSEY: Yes, selling to the ISO. Unlikely that that would happen, but yes.

MR. RAWSON: One more question?

MR. EVANS: Yes, in the example that you gave about two megawatt limitation to achieve deferral of sufficient capacity and so, in your program do you limit that to, does it have to be one customer that can provide that, or can it be several?

MR. DOSSEY: I think it could be multiple customers. I can't imagine the economics of multiple demand limitation systems and communication systems. I think two customers would work just fine, three maybe. But we're looking really for large customers.

MR. EVANS: Yeah.

MR. DOSSEY: But two customers could happen. In fact, wanting to have one of these installation, if I find two customers it will happen that way.

MR. EVANS: I actually think that's, it's an "AHA", at least for me. And that is, deferral is a value. Among all the values we've talked about deferral is a value. In order to have enough and to have sufficient physical assurance to be able to call it deferral, it sounds like if you have -- what did you say, 600 customers?

MR. DOSSEY: A population of 600 on a distribution system.

MR. EVANS: Right, and then 60 circuits out of how many circuits? A lot. You know, you may end up with a pretty small pool for deferrals.

MR. DOSSEY: I believe that's true.

MR. EVANS: Which I think is an interesting, kind of somewhat surprising outcome to me. It'll be interesting to see how this goes.

MR. DOSSEY: Yes.

MR. RAWSON: Thank you, Tom and Ellen. The last presentation, we're going to kind of come full circle here. We started out the day talking about how utilities do distribution planning and innovative distribution planning. We talked about evaluation.

We talked about recently deferral and how agreements are going to be structured with customers.

We're going to finish the day with Rich Seguin again, talking about how they structure agreements with customers in their service territory for providing systems benefits.

MR. SEGUIN: Hi, it's me again. I'm not a lawyer, so I don't know about agreements to much, so bear with me.

I'll talk to you about distribution solutions. The utility-owned generator installed and partnering or leasing a customer generator, and then something we call premium power, which is kind of a sharing of the generation and the benefit of a generator.

Detroit Edison places a generator, he owns it and can operate it. A customer gets standby power out of it, and we operate it if we need to, so it's kind of a sharing.

Distribution solution is what I'm electing to call it. It's utility owned, and we've seen that earlier, that's the one megawatt natural gas at Grosselle school systems between the junior high school and the high school.

Siting is kind of a difficulty. I think it's kind of like a sales pitch, you know. And so, if you've got a good video that don't allow them to interrupt you've got a pretty good chance of making headway with the customer for the utility. We've already seen that.

Again, going back to our definitions -- emergency, temporary and permanent. It's nice to keep things emergency and temporary. I agree with Tom, two years is a nice time frame. For three, it turns out we've had now maybe two and we're saying "gee, could you leave it in there another year?"

But really, that's only because the planner gets an opportunity to look at the load and look at what his resources are. He's not faced with knowing he's got to make a decision in two to three years and feeling he has an obligation to serve, right?

He now can see out another year, see how this thing works and gets comfortable with it, and he's taken another year to defer.

Siting, of course we like things out in the circuit, not necessarily out at the substation. I suppose if we need generation capacity substation's a pretty good place to put it. If you're trying to off the load on a transformer you might have a good shot at it, but most of ours are either transformer or -- we call them getaway cables. So it's got to be out in the circuit somewhere.

So we need a place we can hold from the substation. We too are looking for larger customers, and what Tom was saying, you know, it's location, location, location.

We have customers and we've got overloads. But if we got three percent of our circuits have issues, I'm going to look at all our customers and, the right customer, we've got a three percent chance of being right. So sometimes it's pretty hard to find him, but you do find him.

And then of course you talked about being obscure and etc. And I think when the utility is trying to place it, I think schools and municipalities and etc. are nice places, out of sight and out of sound, and there's something civic about partnering with some of these folks, putting all your utilities together.

And here's our Grosselle. It's a little island at the mouth of Lake Erie at the end of the Detroit River. And we made that presentation to the Grosselle school system and the planning folks. We did a homemade video and we got an amplifier and a portable DB meter and the closest neighbor got out there and they were on cell phones with his wife, and we turned it up to 74 decibels and, you know, can you hear me yet kind of thing.

And she couldn't hear it, and somehow they seemed to like it, and we got it in there. But we shared with them not only the video, but their specific problem. We've got an overload on this circuit, and it's this circuit in green.

And you're located right here, you're kind of on the end of it, and it kind of makes sense to put it there.

And what's our criteria? We need something remote and etc., and we'd share that with them. We'd ask them for help on where to put it.

There's the junior high school, there's the high school. I wanted to put it down here in the corner behind the trees on the parking lot, closer to the gas.

And they said no, how about between the girl's soccer and the baseball diamond? We'll give you a little part tucked up in the woods.

And the house was this house back here, about 600 feet away, so obviously they didn't hear it. They can hear the girls scream though when they're playing soccer.

And we also shared with them the loading for the previous year, to say well, you know, what's the problem going to look like. Well, last year when we had 27 days, typically we have 12 to 15, here are the temperatures and the times and hours we would have to run generators in order to keep the load down to an acceptable level on this circuit.

And then we showed them graphically what it looks like. This is the entire summer, and really on that 27 days I would have only had to run it for seven days.

And an important thing to note, the hours were between one and ten and only up to half of the output of the generator. And of course, I love this quote, it's just kind of -- sometimes we put a lot of words around stuff, and maybe there's a lot of truth to this.

We've tried to disguise our real objectives by putting too many words around it. So I think, particularly if you're approaching an individual customer, why would you give them a 27 page document to review? He says "I need a lawyer."

You give him three pages and a lot of

white space, he'll lease his land. You know the story, then maybe he can look at it and say well, this has merit.

He may even show it to a lawyer, but I want you to put this in here, I want you to say we're going to have a meeting of the planning board and they have to approve an extension of this, because we want to make sure you're temporary, and we put that in for them.

And what does it go into, you have to look at this, again I'm not a lawyer, these are pretty much a standard land lease, no different, except for it has a term.

The lease payment is negotiated. I think we get $750 a month to locate one satellite on our tower as rental. If you take a look at the square footage we're going to occupy, and this is not on the water, it's about $12,000 a year to store something like this on a piece of property, right.

I mean, for both, like say you're going to store it. And that's what we offered them, and that's what they accepted.

And kind of, we backed into it. I don't know, I'd like to say we engineered it to come up with it exactly, but it was kind of a negotiated thing. I think they like having the money and it seems like a nice thing for us to do.

Okay, and then we've got customer. So we talked about us putting it out there, because we can't find customers in the right spot. Well, you see, we've done quite a bit of stuff and we haven't been able to find a whole lot of customers in the right spot but I have one, and it turns out to be a water board, and he's in the right spot.

And he's got this older Caterpillar generator that's just siting there waiting for us to outage him. So we're negotiating with him, we've gotten to the point where we've agreed to everything technically, the lawyers are going through some of the details of the contract. My hope is we're going to have it done this month here.

It's basically the same general lease, except it's kind of like leasing a used car, okay. The big thing is trying to affix value and to bring it to a certain state of maintenance so we can feel comfortable using it, right, both sides. And to reach agreement between the two if something does go south how are we going to split it up, who's going to split up the payments, etc.

And we agree that we both have need of this generator, so we've agreed to share the cost of a replacement if something goes down. And of course in Michigan you're allowed to run standby's 500 hours, not 250 as I guess is here in California, so we're saying we don't want you playing around with it more than 100 hours a year unless we're the cause of you're having to use it.

And we'd like our time not to exceed 400 hours. We don't run it just for fun because it's expensive. And our maintenance dollars are tied to the number of hours that it's running, so it's a fuel delivery.

We will monitor, we'll put in all the monitor and communication and control equipment, we'll put in a closed transition. Right now he doesn't have it, he gets a bump in and out, well, he gets a bump out. It's a bump coming back too.

So we'll put in a seamless transfer switch for him too. So when we use it he doesn't even know. Well, he knows but he doesn't see anything wrong with his load.

And we've put this in sub because his load's not quite enough to cover what we need on the circuit. And it's one of the things that I think Tom has with the physical assurance, he has to be a little cautious about what the load is. He may be forecasting it at peak load.

Maybe the time of the system peak his load is not quite that high, and if, heaven forbid, he would have to outage that load we may not be able to get enough. It's just, this way we've already forecasted that and say we need the whole generator and we're going to put it in sellback.

What else. I guess that's about it. Oh, we're going to do a baseline inspection including infrared to figure out how good the use is and assess value and figure out payment.

The lease payment is negotiated. Remember that example I talked about the boat, that seemed to fly. I played handball with the engineer for -- which is not the reason why I'm staying on the negotiation, but I called and I said "how did it go there?"

And he was calling me about playing handball, and he said "well, can you help me out with $1000?" You know, $1,000 a month.

Okay, premium power. So we talked about

the utility putting the generator in, and maybe the reason why, because I think we can be successful putting it in. Finding the customer in the right spot is really a challenge, it may be hard to do that.

But you can do a general across the system. I don't have it in the presentation, but standby generation is, we're selling a lot of it. obviously the whole northeast helps selling them. And so why shouldn't the utility get into that, it's providing service to their customers and provides benefit to the other ratepayers of the state.

So that's at a higher level, how premium power can be. And what it is is a standby generator, but the equipment is installed, designed and maintained by Detroit Edison. It's a standard length contract, seven to ten years.

I took out the fact that it's only available to bundled customers, because we'd like to keep them captive, but if we're going to have an investment there it's an important thing to do. See, I should have left it in, I was going to talk about it anyway.

Now when you're dealing with a generator you're going to want it to work, right. So you want to monitor it much like we are at the water board, to make sure that it's in good condition when you really need it.

And we think by monitoring it and doing regular starts and maintenance and looking at the temperature when it runs up and etc. is a good way to give us a little better feeling of it working, right. So it's there when we need it.

We put in closed transition switching. Normally it's in non-sellback. That ASC that we looked at earlier in the day, that car company that saved some CIAC because they were adding load and we talked them into this and interruptible rates at the same time, we just got it done. We got the ink dry.

And the planning engineer decides, gee it would be nice if I had more generation there. Well, probably next year we may go back to them and look at putting additional generation and turning it into a sellback.

The benefits to the utility. Of course it can provide reduction constraints of transmission distribution. It's an alternative for a second feed, right. And as that, it can capture some additional benefit, maybe up to 20 percent of it by going up to interruptible rate.

It helps the customer retention and increased customer satisfaction. We've had phone calls, more from residential, but believe it or not, they actually trust Detroit Edison. They're a little nervous about generator suppliers coming out there wanting to sell them a generator.

Somehow they figure we're not going anywhere. We've been there for over 100 years, and there's a feeling of trust that we know the electrical system and that we're not going to rip them off. And so there's a certain belief in there.

And it requires, a benefit to them that requires no down payment. It's fixed monthly, it's off balance sheet, we do about everything for them, right. And they pay for it a little each month on their bill.

And we build it as a turnkey for them. We monitor it, we fill it up, take care of the fuel and etc. We sell them their power, whatever it is. If we happen to generate it with expensive stuff on a particular day they don't care, right.

They don't have any tariff issues. It's

up to us to eat the cost differential between using cheap generation to sell them their kilowatts. And since we don't want any rate issues, if they move to the interruptible we will guarantee the fact, if it doesn't start we'll pay the penalties. We'll still assess them, but we'll give them the money.

And all that's put into the NPV modeling for this, the fact that we'll have a ceratin percentage of failures, it may happen, and again that's what emergency ratings are for. Particularly if you own it, why not afford yourself that opportunity.

And it's, about the contract, it's basically modeled after standard redundant service agreement. We do check their financials and stuff like that. And that's all I have.

MR. RAWSON: Thank you, Rich. I'm going to turn it over to the dais for any questions, and then we'll close it out. John?

COMMISSIONER GEESMAN: One quick question on the deal that you've got there, that you're negotiating with the water board. That's a public agency?

MR. SEGUIN: Yes.

COMMISSIONER GEESMAN: So they're going to be around. Would you feel comfortable negotiating a similar deal with a private business that may face the risk of business failure next year?

MR. SEGUIN: Well, we do that with the premium power program, of course.

COMMISSIONER GEESMAN: Sure.

MR. SEGUIN: I mean, we're running the entire cost of it. And we do check their financials and etc. as a part of that. I think we probably would just do that also on one of these.

COMMISSIONER GEESMAN: Okay.

MR. SEGUIN: There's an awful lot of water board generation up there. It would be nice to capture some of that. I think actually they're exempt from FERC regulation,, water municipality, you know.

So maybe you don't have the ISO difficulties of sellback.

COMMISSIONER GEESMAN: No comment. Thank you very much.

You know, I don't want to say very much because I think it's all been said, but everyone has said it.

Other than to recognize each of you for sticking through two days. It's been a very informative two days for us. I think we've developed a very rich evidentiary record that we'll make good use of going forward.

A special thanks to each of our speakers. And I recognize the extent of the work that went into preparing your remarks.

We've also got some very well informed reports now that we've posted on our website. We're inviting written comments until I think May 6th, and I look forward to going through each of those.

And then finally, a special thanks to both Mark Rawson and Scott Tomashevsky for assembling two very information packed days.

With that, we'll be adjourned.

(Thereupon, the workshop ended at 3:51 p.m.)

CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Business Hearing; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said meeting, nor in any way interested in outcome of said meeting.

IN WITNESS WHEREOF, I have hereunto set my hand this 18th day of May, 2005.